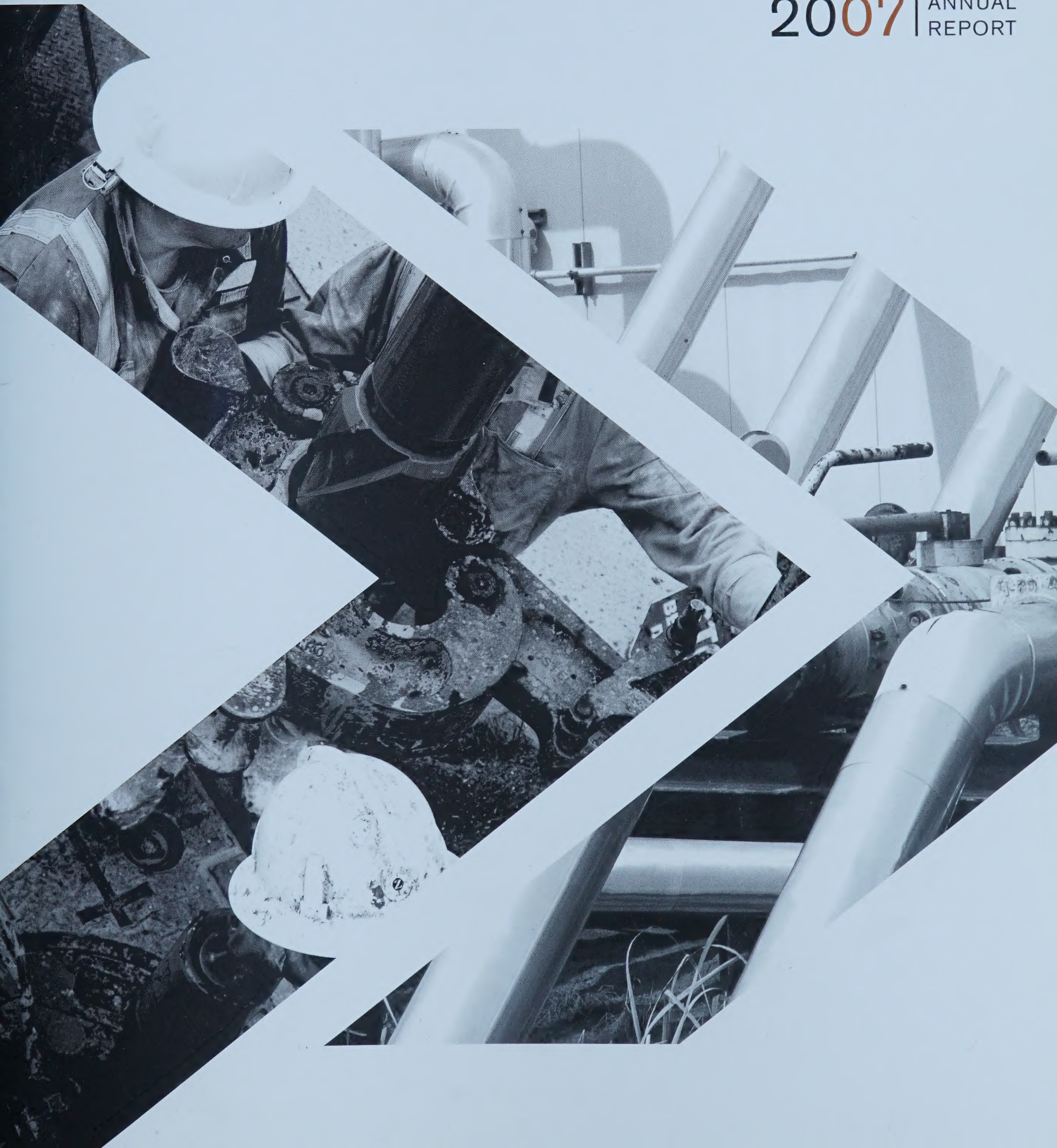
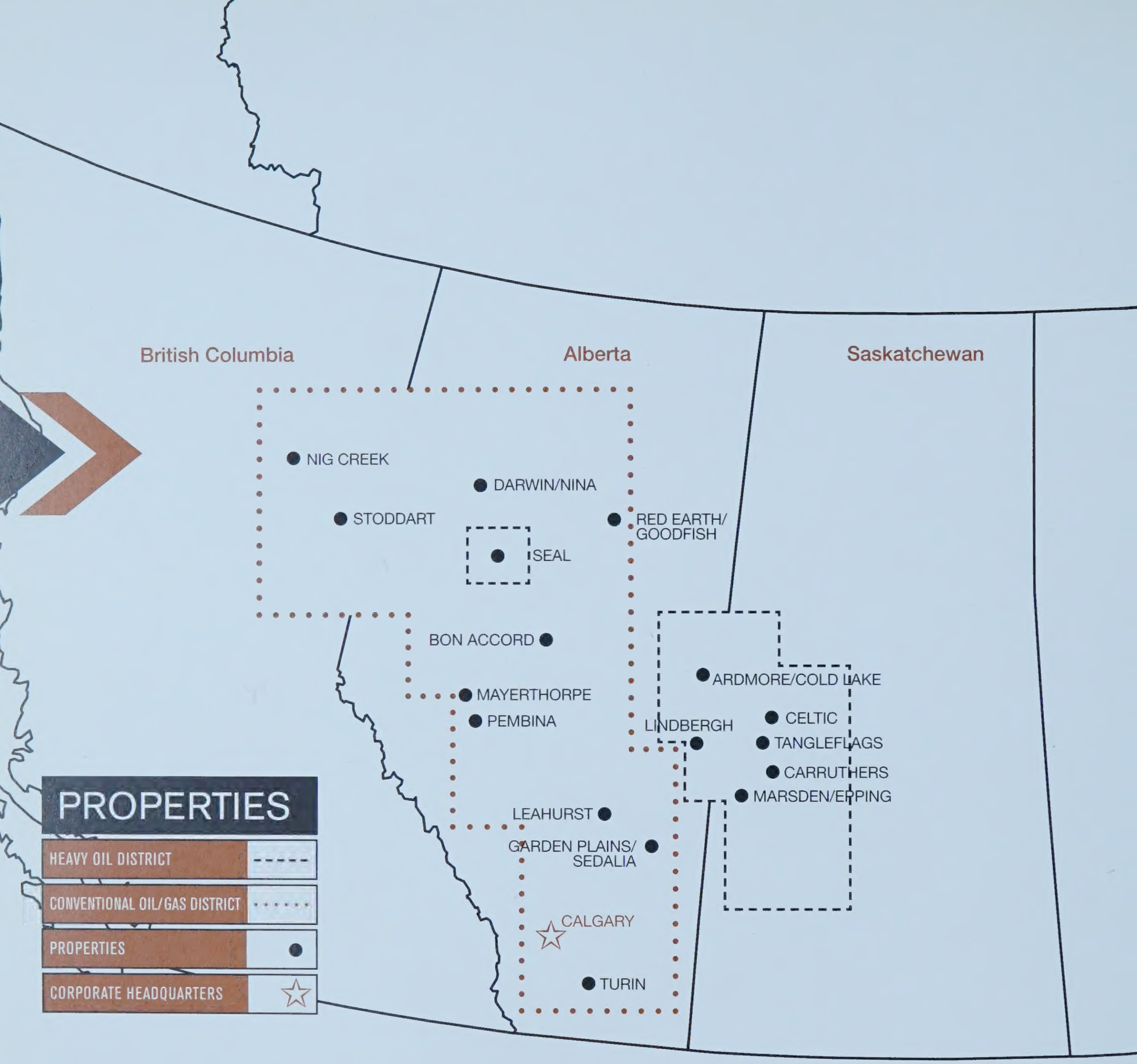
BAYTEX

ENERGY TRUST

2007 | ANNUAL REPORT




British Columbia
Alberta
Saskatchewan
NIG CREEK
DARWIN/NINA
STODDART
RED EARTH/
GOODFISH
SEAL
BON ACCORD
ARDMORE/COLD LAKE
MAYERTHORPE
PEMBINA
LINDBERGH
CELTIC
TANGLEFLAGS
CARRUTHERS
MARSDEN/EPPING
LEAHURST
GARDEN PLAINS/
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HIGHLIGHTS

Year ended December 31	2007	2006	% change
Financial *(thousands of Canadian dollars, except per unit amounts)*			
Petroleum and natural gas sales	**618,927**	556,689	*11*
Cash flow from operations[1]	**286,030**	274,662	*4*
Per unit – basic	**3.57**	3.77	*(5)*
– diluted	**3.34**	3.45	*(3)*
Cash distributions	**145,927**	143,072	*2*
Per unit	**2.16**	2.16	–
Net income	**132,860**	147,069	*(10)*
Per unit – basic	**1.66**	2.02	*(18)*
– diluted	**1.60**	1.91	*(16)*
Capital expenditures			
Exploration and development	**148,719**	132,381	*12*
Acquisitions *(net)*	**245,427**	702	*n/a*
Total monetary debt[2]	**444,065**	366,810	*21*
Trust units outstanding at December 31 *(thousands)*[3]	**87,169**	77,498	*13*
Operating			
Production			
Light oil and NGL *(bbl/d)*	**5,483**	3,735	*47*
Heavy oil *(bbl/d)*	**22,092**	21,325	*4*
Total oil *(bbl/d)*	**27,575**	25,060	*10*
Natural gas *(MMcf/d)*	**51.9**	55.4	*(6)*
Oil equivalent *(boe/d)*[4]	**36,222**	34,292	*6*
Reserves, proved plus probable[5]			
Oil and NGL *(Mbbl)*	**143,266**	120,443	*19*
Natural gas *(Bcf)*	**148.9**	148.1	*1*
Oil equivalent *(Mboe)*	**168,076**	145,120	*16*
Reserve life index *(years, proved plus probable)*	**12.3**	11.6	*6*

(1) Cash flow from operations and cash flow from operations per unit are non-GAAP terms that represent cash generated from operating activities before changes in non-cash working capital and other operating items (see reconciliation under MD&A). The Trust's cash flow from operations may not be comparable to other companies. The Trust considers cash flow a key measure of performance as it demonstrates the Trust's ability to generate the cash flow necessary to fund future distributions and capital investments.

(2) 2007 year end balance of 444,065 total monetary debt excludes the following non-cash items: future income tax assets, unrealized losses on financial derivative contracts, and the fair value hedge adjustment recorded upon adoption of Financial Instruments Accounting pronouncements.

(3) Number of trust units outstanding includes the conversion of exchangeable shares at the respective exchange ratios in effect at the end of the reporting periods.

(4) Oil equivalent amounts have been calculated using a conversion rate of six thousand cubic feet of natural gas to one barrel of oil. BOEs may be misleading, particularly if used in isolation. A BOE conversion ratio of 6 Mcf:1 bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

(5) Reserves information as at December 31, 2007 and 2006 is prepared in accordance with NI 51-101.

MESSAGE TO UNITHOLDERS

We are very pleased to report, once again, record results to our unitholders. In 2007, we achieved the highest production and cash flow in our history as a trust, added high quality light oil production and exploration prospects, advanced development of our valuable oil sands resource assets, maintained our industry-leading capital efficiency and further strengthened our financial position and sustainability.

Operations Review

We began the year with an exploration and development capital budget of $140 million designed to maintain production at levels consistent with those of previous years. Our operational focus was to continue to develop our in-house inventory of prospects, most notably our large resource assets at Seal in the Peace River oil sands region of northern Alberta. The results of our 2007 drilling program were excellent and comparable to our historical performance, with an overall success rate of 96% in the drilling of 136 wells. Included in this program were 17 horizontal production wells at Seal drilled at a 100% success rate with production levels meeting or exceeding expectations. These results, together with positive production performance during the year from the other eight wells drilled in previous years, allowed our independent reserves evaluator to recognize 28.7 million barrels of proved plus probable reserves at Seal at the end of 2007, an increase of 120% over those of one year ago. This success validates our prudent and methodical approach over the past few years in developing the vast resource in this area. We have planned a similar development program at Seal in 2008, including the drilling of 15 to 20 horizontal production wells and a number of stratigraphic test wells, together with the commencement of our first thermal recovery pilot test in the first half of this year.

In addition to focusing on internal property development, our corporate strategy also targets the acquisition of high quality assets with potential for growth. The asset acquisitions at Stoddart in 2004 and at Celtic in 2005 were examples of such value accretive transactions. In June 2007, we completed the largest acquisition in our history at a price of $241 million, adding to our portfolio high quality light oil and natural gas assets at Pembina in the prolific Nisku trend and profitable heavy oil operations at Lindbergh. Both areas contain numerous exploration and development opportunities and the transaction was accretive on a per unit basis to our production, cash flow, reserves and net asset value. The Pembina assets are primarily responsible for our success in increasing our corporate light oil and natural gas liquids reserves by 78% from a year ago. We are particularly excited to have acquired these reserves at reasonable costs under a record oil price environment.

The Pembina/Lindbergh acquisition represents a step growth in our evolution. Production averaged 38,698 boe/d for the second half of 2007, reflecting the full contributions of the new assets, and 36,222 boe/d for the year. Our total capital program for 2007 amounted to $394 million. The efficiency of this program was outstanding and resulted in finding, development and acquisition ("FD&A") cost of $10.90/boe on a proved plus probable reserves basis before changes in future development cost. Combined with operating netback of $26.43/boe, our investment recycle ratio for the year was a stellar 2.4. This ratio is particularly meaningful as our production netback was weighted 61% towards heavy oil, which has a lower per barrel netback than light oil, yet our capital spending was weighted 73% towards light oil and natural gas, which generally command a higher FD&A cost. Our results clearly demonstrate both the robust economics of our heavy oil operations and the superior efficiency of our overall capital program.

Another measure of capital efficiency and operational sustainability is the reserves replacement ratio. For 2007, we replaced 123% of production through an exploration and development capital program that amounted to only 52% of our cash flow. Together with our acquisition efforts, we replaced production by 274% with total capital expenditures equal to only 138% of cash flow. These outstanding results are also consistent with our long-term performance, with our three-year average (2005-07) FD&A cost of $7.83/boe, recycle ratio of 3.4 and reserves replacement ratio of 224% all ranking among the best in our industry.

Financial Review

Crude oil and natural gas prices charted remarkably different courses during 2007. It seems almost impossible that in January world oil prices actually traded around US$50.00/bbl but then went on an unprecedented ascent with WTI closing the year at US$95.98/bbl. WTI price averaged an all-time high of US$72.31/bbl in the year, an increase of 9.2% over a year ago. However, the impact on Canadian producers was muted by a strengthening Canadian currency, which averaged US$0.9304 in the year or 5.5% higher than the year prior. Overall, benchmark Edmonton par crude averaged $76.35/bbl in 2007 or 4.9% higher than one year ago. Natural gas prices, on the other hand, never experienced the rebound that was generally anticipated. Alberta spot price averaged $6.72/Mcf during the year, 5% below that of one year ago and 22% below the all-time high annual average set in 2005.

While the soft natural gas prices did have the effect of reducing demand for certain oilfield services, the impact on slowing inflation was mostly experienced in capital spending. Operating expenses for production operations continued to increase as major expense items such as labour, property taxes and fuel were all higher. For the year, our operating expenses were $10.09/boe, an increase of 12% over those of one year ago. This increase is also partly due to the new sour oil and gas operations acquired in Pembina. Transportation expenses increased 11% to $2.16/boe due to higher fuel costs and longer haul distance for production at Seal, and general and administrative expenses increased 6% to $1.77/boe, reflecting the tight labour market and inflationary environment in our Calgary head office.

Cash flow for the year was a record $286 million, an increase of 4% over the previous record set in 2006. However, as our asset base was significantly enhanced by the acquisition completed at the end of June, operating results for the second half of the year are more indicative of our current capabilities. Cash flow during the second half of 2007 was $174 million ($2.09 per basic unit), generated under average benchmarks of WTI at US$83.03, USD/CAD exchange rate at 0.9870, Lloyd Blend differential at 33% and AECO monthly index at $5.65/Mcf. Our payout ratio for this six-month period was 44% net of our Distribution Reinvestment Plan ("DRIP") and 52% before DRIP. These metrics bode well for our 2008 outlook as commodity prices have increased substantially from those levels.

Total monetary debt at year-end 2007 was $444 million. Approximately 40% of that was represented by the US dollar denominated senior subordinated notes which provide a natural hedge against the foreign exchange exposure on our production revenue. This level of debt equates to 1.3 times annualized second half cash flow. Undrawn credit facilities at year-end were approximately $120 million providing Baytex with excellent financial resources and flexibility to manage our business going into 2008.

Industry Development

The federal government's Tax Fairness Plan, despite intense lobbying efforts from the Canadian Association of Income Funds, the Canadian Coalition of Energy Trusts and the Canadian Association of Income Trust Investors, was enacted in 2007. Although the applicable tax rates have been moderated from the originally proposed levels, the prospect of this pending tax change has significantly dampened the interest and support of the capital markets with respect to income trusts. For 2008, we plan to execute a business plan that is similar to that of our historical model under the income trust structure. Baytex's corporate strategies and operational and financial undertakings have always been guided by sound economic principals and proper governance practices. We also possess a successful track record of operating as an exploration and production corporation for 10 years prior to the conversion to an income trust in 2003. With our high quality asset base and excellent operational and financial flexibility, Baytex will adjust our corporate model as required as we approach 2011 in order to maximize returns to our stakeholders.

In October 2007, based on the recommendations of a government-appointed panel, the Government of Alberta announced the New Royalty Framework ("NRF") that affects the economics of virtually every kind of oil and gas project in the province beginning in 2009. The NRF creates a great level of controversy as the oil and gas industry submits that the Government was presented with incomplete and obsolete data, especially in relation to the prevailing cost structure in the oil and gas industry. The Government has indicated that as the new royalty regime is further developed, "adjustments may be made to ensure there are no unintended consequences to its decisions". Within Baytex's production operations, where approximately 40% on a boe basis is in Alberta, the area that could be most affected is our deep oil operation in Pembina. Based on limited details available at this time, our independent

reserves evaluator has estimated that the change due to the NRF to the net present value, discounted at 10%, of future net revenue from our proved plus probable reserves would be a reduction of 2.1% under the forecast price assumptions. While the materiality of the potential impact is not critical with respect to existing reserves, we are working through designated industry groups with the Government to further consider the need for amendments in order to address any "unintended consequences" in relation to future capital investments in Alberta.

Outlook

We have planned a capital budget of $150 million for 2008 designed to maintain our production between 37,000 and 38,000 boe/d. Based on this operating plan and under current commodity prices, our cash flow and financial position are projected to further improve from 2007 levels. These strong fundamentals, together with our strategy to deliver optimum returns to our investors, have allowed us to increase our monthly cash distributions to $0.20/unit beginning with our distribution payment in April 2008. This is the second distribution increase we have implemented since our inception as a trust, without any such decrease during this period, demonstrating our strategy and resolve in delivering consistent returns to our investors. We are projecting that cash flow in 2008 will be sufficient to fully fund our capital spending and distributions at this increased level.

We accept the higher challenges brought on by recent industry developments. Our mandate is to continue to improve on our asset base in order to sustain our superior capital efficiency. Long-term projects such as Seal and Pembina will help in executing this mandate. We also recognize the importance of appropriate diversification and expansion, both from the stand point of geographic and prospect exposure. In this regard, we are excited about our decision to begin operations in the United States with the opening of our office in Denver, Colorado in late 2007. We believe that this initiative will lead to increased opportunities for efficient capital deployment.

From the beginning of October 2003 to year-end 2007, our total returns to unitholders was 32.8% on an annualized basis, ranking us as one of the most successful oil and gas income trusts during this period with respect to market performance. We want to express our appreciation for the support from our unitholders, and look forward to continue to deliver superior value to our investors.

On behalf of the Board of Directors,

Raymond T. Chan, CA
Chief Executive Officer
March 17, 2008

MANAGEMENT'S DISCUSSION AND ANALYSIS

The following Management's Discussion and Analysis ("MD&A"), dated March 17, 2008, should be read in conjunction with Baytex Energy Trust's (the "Trust" or "Baytex") audited consolidated financial statements for the fiscal years ended December 31, 2007 and 2006. Per barrel of oil equivalent ("boe") amounts have been calculated using a conversion rate of six thousand cubic feet of natural gas to one barrel of oil, which represents an energy equivalent conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. BOE's may be misleading, particularly if used in isolation.

The Trust evaluates performance based on net income and cash flow from operations. Cash flow from operations and cash flow per unit are not measurements based on generally accepted accounting principles ("GAAP"), but are financial terms commonly used in the oil and gas industry. Cash flow represents cash generated from operating activities before changes in non-cash working capital, deferred charges and other assets and deferred credits. The Trust's determination of cash flow may not be comparable with the calculation of similar measures for other entities. The Trust considers cash flow from operations a key measure of performance as it demonstrates the ability of the Trust to generate the cash flow necessary to fund future distributions to unitholders and capital investments. The most directly comparable measure calculated in accordance with GAAP is cash flow from operating activities, and net income per unit. A reconciliation of net income to cash flow from operations and cash flow from operating activities is shown under Quarterly Information.

The Trust also uses certain key performance indicators and industry benchmarks such as operating netback ("netback"), finding, development and acquisition costs ("FD&A"), recycle ratio and total capitalization to analyze financial and operating performance. These key performance indicators and benchmarks as presented do not have any standardized meaning prescribed by Canadian GAAP and therefore may not be comparable with the calculation of similar measures for other entities.

This MD&A contains forward-looking statements relating to future events or future performance. In some cases, forward-looking statements can be identified by terminology such as "may", "will", "should", "expects", "projects", "plans", "anticipates" and similar expressions. These statements represent management's expectations or beliefs concerning, among other things, future operating results and various components thereof or the economic performance of the Trust. The projections, estimates and beliefs contained in such forward-looking statements necessarily involve known and unknown risks and uncertainties, including the business risks discussed in the MD&A as at and for the years ended December 31, 2007 and 2006, which may cause actual performance and financial results in future periods to differ materially from any projections of future performance or results expressed or implied by such forward-looking statements. Readers should not place undue reliance on any such forward-looking statements, which speak only as of the date they were made. Except where required by securities legislation, the Trust is not obligated to publicly update or revise the forward-looking statements relating to future events or future performance to reflect any change in management's expectations or events.

Baytex Energy Trust was established on September 2, 2003 under a Plan of Arrangement. The Trust is an open-ended investment trust created pursuant to a trust indenture. Subsequent to the Plan of Arrangement, Baytex Energy Ltd. (the "Company") became a subsidiary of the Trust.

Prior to the Plan of Arrangement, the consolidated financial statements included the accounts of Baytex and its subsidiaries and partnership. After giving effect to the Plan of Arrangement, the consolidated financial statements have been prepared on a continuity of interests basis which recognizes the Trust as the successor to Baytex. The consolidated financial statements include the accounts of the Trust and its subsidiaries and have been prepared by management in accordance with Canadian generally accepted accounting principles.

2007 OVERVIEW

The Trust strives to be self-sustaining from an operational and financial perspective, relying primarily on internal property development to provide production and reserves replacement. The Trust plans to fund its ongoing program along with distributions substantially from internally generated cash flow. Significant acquisitions may be funded through a combination of debt and equity issuance. During 2007, the Trust executed a successful capital program replacing 123% of production (on a proved plus probable basis) by spending 52% of cash flow from operations and 274% of production by an overall capital program including acquisitions, equal to 138% of cash flow.

On June 15, 2007, we completed a public offering of 7,000,000 Subscription Receipts (the "Sub Receipts") for gross proceeds of $149,450,000. Upon the June 26, 2007 closing of the property acquisition described below, the holders of the Sub Receipts received one trust unit in exchange for each Sub Receipt held. The net proceeds of this financing were used to partially fund the acquisition of properties at Pembina and Lindbergh.

On June 26, 2007, we completed the acquisition of certain oil and gas properties in the Pembina and Lindbergh areas of Alberta for total cash consideration of $241 million. These assets were producing approximately 4,500 barrels of oil equivalent per day ("boe/d") of total production at the time of the acquisition. This production was comprised of 2,200 barrels per day ("bbl/d") of light oil and NGL and 8.0 million cubic feet per day ("MMcf/d") of natural gas from the Pembina area, and 1,000 bbl/d of heavy oil from the Lindbergh area. The acquisition in the Pembina area allowed us to establish a new core area in the Nisku trend, offering greater exposure to high netback light oil and NGL targets. The assets included one of the strongest infrastructure positions in the area, which contributed to our high degree of operational control of the area, and included 26,000 net acres of undeveloped land in the Pembina area. Lindbergh is a project that offers a large heavy oil resource in place that is amenable to primary (cold) production. Its shallow-depth and multiple zone character provide a low-cost source of recompletion and drilling inventory to maintain production rates. In addition to the primarily non-operated producing assets, Baytex also acquired 11,000 net acres of 100% interest undeveloped land that may include opportunities for shallow natural gas development.

PROPERTY REVIEW

Oil and Natural Gas Properties

The following is a description of our principal oil and natural gas properties on production or under development as at December 31, 2007. Unless otherwise specified, gross and net acres and well count information are as at December 31, 2007. Well counts indicate gross wells, except where otherwise indicated. Production information represents average working interest production, for the year ended December 31, 2007, except where otherwise indicated.

Baytex's crude oil and natural gas operations are organized into two operating districts: the Heavy Oil District and the Conventional Oil and Gas District. Each district has an extensive portfolio of operated properties and development prospects with considerable upside potential. Within these districts, Baytex has established a total of eight geographically-organized teams with a full complement of technical professionals (engineers, geoscientists and landmen) within each team. This comprehensive technical approach results in thorough identification and evaluation of exploration, development and acquisition investment opportunities, and cost-efficient execution of those opportunities.

Heavy Oil District

The Heavy Oil District accounts for more than 55% of current production, more than 70% of oil-equivalent reserves and over half of Baytex's cash flow from operations. Baytex's heavy oil operations consist predominantly of cold primary production, without the assistance of steam injection. In some cases, Baytex's heavy oil reservoirs containing lower-than-average viscosity crudes are waterflooded, occasionally with hot water. Baytex's heavy oil fields often have multiple productive zones, some of which can be commingled within the same producing wellbore. Production is generated from vertical, slant and horizontal wells using progressive cavity pumps capable of handling large volumes of heavy oil combined with gas, water and sand. Initial production from these wells usually averages between 40 and 100 bbl/d of crude with gravities ranging from 11 to 18 API. Once produced, the oil is trucked or pipelined to markets in both Canada and the United States. Heavy crude is usually blended with a light-hydrocarbon diluent (such as condensate) prior to being introduced into a sales pipeline. The blended crude oil is then sold by Baytex and may be upgraded into lighter grades of crude or refined into petroleum products such as fuel oil, lubricants and asphalt by the crude purchasers. All production rates reported are for heavy crude only, before the addition of diluent.

In 2007, production in the Heavy Oil District averaged approximately 22,100 bbl/d of heavy oil and 7,340 Mcf/d of natural gas (23,400 boe/d). Baytex drilled 94 gross (93.5 net) wells in the Heavy Oil District resulting in 87 (86.5 net) oil wells, four (4.0 net) stratigraphic test wells, and three (3.0 net) dry and abandoned wells, for a success rate of 96.8% (96.8% net).

The Heavy Oil District possesses a large inventory of development projects within the west-central Saskatchewan, Cold Lake/Ardmore, and Peace River areas. Baytex's ability to generate relatively low-cost replacement production through conventional cold production methods is key to maintaining our overall production rate. Because of Baytex's large inventory of heavy oil investment projects, we are able to select between a wide range of investments to maintain heavy oil production rates.

Baytex will continue to build value through internal heavy oil property development and selective acquisitions. Future heavy oil development will focus both on the Peace River oil sands area and Baytex's area of historical emphasis around Lloydminster in southwest Saskatchewan and southeast Alberta. Our net undeveloped lands in the Heavy Oil District totalled approximately 295,000 acres at year-end 2007. Our key heavy oil properties are described below.

Ardmore, Alberta: Acquired in 2002, this property has since been extensively developed in the Sparky, McLaren and Colony formations. Average production during 2007 was approximately 1,900 bbl/d of oil and 480 Mcf/d of natural gas (2,000 boe/d). Three successful oil wells and no dry holes were drilled in the area during 2007. Baytex

anticipates drilling three wells in this area in 2008. In addition, new production techniques, such as cold horizontal well production and cyclic steam injection, are being evaluated for the large hydrocarbon resource in this area. Due to extensive Baytex infrastructure in this area, operating expenses in 2007 remained relatively low at approximately $8.20 per boe. Net undeveloped lands were 39,000 acres at year-end 2007.

Carruthers, Saskatchewan: The Carruthers property was acquired by Baytex in 1997. This property consists of separate "North" and "South" oil pools in the Cummings formation. During 2007, average production was approximately 2,300 bbl/d of heavy oil and 780 Mcf/d of natural gas (2,400 boe/d). No new wells were drilled in this area in 2007 but the hot waterflood project was expanded by flowlining to eight existing wells and converting five wells to injection. Net undeveloped lands were 9,900 acres at year-end 2007.

Celtic, Saskatchewan: This producing property was acquired in October 2005, in a transaction which included approximately 2,000 Bbl/d of Steam Assisted Gravity Drainage (SAGD) production. The SAGD production was divested at the end of 2005, leaving Baytex with purchased cold heavy oil production of 1,600 bbl/d and natural gas production of 900 Mcf/d. As a result of Baytex's well re-completion and drilling activities, cold production increased to an average of 4,500 bbl/d of heavy oil and 1,330 Mcf/d of natural gas (4,700 boe/d) during 2007. This production number includes minor production in the area held prior to the Celtic acquisition. Celtic is a key asset for Baytex because, like the adjacent Tangleflags property, it contains a large resource base within multiple prospective horizons. As a result, the Celtic property provides a multi-year inventory of low-cost drilling locations and re-completion opportunities. Also like Tangleflags, the heavy oil at Celtic is relatively highly gas-saturated and the existing infrastructure allows for efficient capture and marketing of co-produced solution gas. In 2008, Baytex expects to drill 25 new wells and re-complete up to 70 existing wells. Net undeveloped lands were 8,300 acres at year-end 2007.

Cold Lake, Alberta: Located on Cold Lake First Nations lands, this heavy oil property was acquired by Baytex in 2001. Production is primarily from the Colony formation. Average oil production during 2007 was approximately 600 bbl/d, during which time Baytex drilled two oil wells. Two new wells are planned for 2008. Net undeveloped lands were 13,600 acres at year-end 2007.

Marsden/Epping/Macklin/Silverdale, Saskatchewan: This area of Saskatchewan is characterized by low access costs and generally higher quality crude oil that ranges up to 18 API. Initial per well production rates are typically 40 to 70 bbl/d. Primary recovery factors can be as high as 30% of the original oil in-place because of the relatively high oil gravity and the existence of strong water drive in many of the oil pools in this area. Average production in this area during 2007 was approximately 2,400 bbl/d of oil and 110 Mcf/d of natural gas (2,500 boe/d). Nine oil wells and one dry hole were drilled in this region in 2007. For 2008, 26 new wells are planned for this area including a 16 well development program to expand the Silverdale Sparky oil pool. A significant facility expansion involving emulsion flow-lining and conservation of the solution gas is also planned for this pool. Net undeveloped lands were 24,300 acres at year-end 2007.

Seal, Alberta: Seal is a highly prospective property located in the Peace River oil sands area of northern Alberta. Baytex holds a 100% working interest in over 100 sections of long-term oil sands leases. In certain parts of this land base, heavy oil can be produced through primary methods using horizontal wells at initial rates of approximately 150 bbl/d per well without employing more capital-intensive methods such as steam injection. During 2007, Baytex drilled four new stratigraphic test wells to identify extensions to our current development area which is located on the western block of these land holdings. Baytex also drilled 17 new horizontal producing wells in 2007, bringing the total number of producing wells to 25. The average production rate during 2007 was 1,600 bbl/d of heavy oil. Baytex plans to drill four additional stratigraphic test wells and 15 to 20 horizontal producing wells at Seal during 2008. Detailed reservoir simulations of the Seal property have indicated that both waterflood and cyclic steam recovery methods have the potential to greatly increase the ultimate recovery factor beyond what is achievable with primary recovery. A horizontal well drilled in 2007 was equipped for steam injection. Following approximately six months of primary production, this thermal test well will undergo an initial cycle of steam injection commencing in the first half of 2008. Baytex also intends to expand the area facilities in the first half of 2008 by constructing a water disposal plant and fuel gas supply pipeline. As the region continues to develop, the Seal property is expected to take an increasingly more prominent role in our production profile. Net undeveloped lands in this area were 56,000 acres at year-end 2007.

Tangleflags, Saskatchewan: Baytex acquired the Tangleflags property in 2000. Tangleflags is characterized by multiple-zone reservoirs with production from the Colony, McLaren, Waseca, Sparky, General Petroleum and Lloydminster formations. Accordingly, this property supplies long-term development potential through a considerable number of uphole re-completion opportunities. In 2007, 16 wells were either re-started or re-completed. Average production during 2007 was approximately 1,800 bbl/d of heavy oil and 950 Mcf/d of natural gas (2,000 boe/d). In 2008, Baytex plans to drill two new wells and re-work about 20 existing wells in this area. Net undeveloped lands were 8,900 acres at year-end 2007.

Lindbergh, Alberta: Lindbergh is a primarily non-operated heavy oil property that was purchased in June of 2007. Oil production at Lindbergh is operated by a senior Canadian producer. Baytex has a 21.15% working interest that yields working interest production of approximately 900 bbl/d of heavy oil. Like Tangleflags and Celtic, Lindbergh is a multi-zone property that is expected to provide future development projects for many years. Thus far, economic production has been obtained from the Dina, Cummings, General Petroleum, Sparky, and Colony intervals. Baytex expects the field operator to maintain a level of activity that would result in relatively flat production rates. Net undeveloped lands were 11,000 acres at year end 2007.

Conventional Oil and Gas District

Although Baytex is best known as a "heavy oil" energy trust, we also possess a growing array of light oil and natural gas properties that generate nearly half of our cash flow. In addition to Baytex's historical light oil and natural gas properties in northern and southeastern Alberta, the geographic scope of our conventional oil and gas operations has expanded to southwest Alberta and northeast British Columbia, providing exposure to some of the most prospective areas in Western Canada.

The Conventional Oil and Gas District produces light and medium gravity crude oil, natural gas and natural gas liquids from various fields in Alberta and British Columbia. During 2007, production from this district averaged approximately 44,500 Mcf/d of natural gas sales and 5,500 bbl/d of light oil and NGL for annual average oil equivalent production of 12,900 Boe/d. During 2007, the District drilled 39 gross (34.0 net) wells resulting in 22 gross (17.5 net) gas wells, 10 gross (9.7 net) oil wells, three gross (2.8 net) service wells and four gross (4.0 net) dry wells for a success rate of 90.0% (88.2% net). Our net undeveloped lands in this District were approximately 344,000 acres at year-end 2007. Our key conventional oil and natural gas properties are described below.

Bon Accord, Alberta: This multi-zone property was acquired by Baytex in 1997. Production is obtained from the Belly River, Viking and Mannville formations. During 2007, production for the area averaged approximately 3,140 Mcf/d of gas and 300 bbl/d of light oil (800 boe/d). Natural gas is processed at two Baytex-operated plants and oil is treated at three Baytex-operated batteries. During 2007, Baytex drilled three oil wells in this area. At year-end 2007, Baytex had 15,000 net undeveloped acres in this area.

Darwin/Nina, Alberta: Both properties in this winter-access area produce natural gas from the Bluesky formation. Natural gas production is processed at two Baytex-operated gas plants. Production during 2007 averaged approximately 2,900 Mcf/d (500 boe/d). During 2007, Baytex installed an amine facility at Darwin to remove carbon dioxide from the sales gas and improve operating capability and product netback for the area. At year-end 2007, Baytex had 41,000 net undeveloped acres in this area.

Leahurst, Alberta: Production averaged approximately 3,900 Mcf/d (700 boe/d) during 2007 from this multi-zone, year-round access area. Natural gas production from the Edmonton, Belly River, Viking and Mannville formations is processed at several plants, one of which is Baytex-operated. During 2007, Baytex participated in the drilling of 10 operated and three non-operated locations, resulting in 13 producing gas wells. During 2008, Baytex plans to drill up to five wells in this area. At year-end 2007, Baytex had 14,900 net undeveloped acres in this area.

Pembina, Alberta: Baytex acquired its position in this area in June 2007. Production is primarily obtained from the Nisku formation and to a lesser extent from the Ellerslie, Glauconite, Notikewin, Rock Creek and Nordegg formations. The majority of Baytex's production in this area is treated at a Baytex-operated oil battery with the remaining production treated at two third-party oil batteries. Gas production is delivered for further processing to a combination of four mid-stream gas processing facilities in the area. From July to December 2007, production averaged approximately 3,900 bbl/d of light oil and and NGL and 7,800 Mcf/d of gas (5,200 boe/d). During 2007,

Baytex drilled two Nisku tests that, while unsuccessful in the targeted formation, were cased as potential water source wells to support future water injection requirements. Baytex plans to drill four gross wells in this area during 2008. At year-end 2007, Baytex had 11,200 net undeveloped acres in this area.

Richdale/Sedalia, Alberta: In 2001, Baytex acquired its initial position in this area and significantly increased its presence with a 2004 acquisition of a private company. During 2007, production averaged approximately 7,300 Mcf/d of gas (1,200 boe/d). This area has advantages of year-round access and multi-zone potential in the Second White Specks, Viking and Mannville formations. Most of the gas production from this area is processed at two Baytex-operated gas plants. During 2007, Baytex drilled three gas wells in this area. At year-end 2007, Baytex had 36,100 net undeveloped acres in this area.

Red Earth/Goodfish, Alberta: This primarily winter-access, multi-zone property was acquired by Baytex in 1997. Oil production from Granite Wash and Slave Point pools is treated at two Baytex-operated sweet oil batteries. Natural gas production from the Bluesky formation is handled at two gas plants, one of which is Baytex-operated. Production from this area during 2007 averaged approximately 4,330 Mcf/d of and 600 bbl/d of light oil and NGL (1,300 boe/d). During 2007, Baytex drilled one oil well in this area. At year-end 2007, Baytex had 33,700 net undeveloped acres in this area.

Stoddart, British Columbia: The Stoddart asset acquisition was completed in December 2004. Oil and liquids rich gas production from this largely year-round-access area comes from the Doig, Halfway, Baldonnel, Coplin and Bluesky formations. Oil is treated at two Baytex-operated batteries and natural gas is compressed at four Baytex-operated sites and sent for further processing at the outside-operated West Stoddart and Taylor Younger plants. Production from this area during 2007 averaged approximately 11,200 Mcf/d of gas and 1,800 bbl/d of oil and NGL (3,700 boe/d). Baytex drilled 11 wells in 2007 resulting in seven oil wells and four dry holes. During 2008, Baytex plans to drill up to six wells and re-complete several wells in the area. At year-end 2007, Baytex had 33,300 net undeveloped acres in this area.

Turin, Alberta: This multi-zone, year-round access property was acquired in 2004 with the acquisition of a private company. Production during 2007 averaged approximately 600 bbl/d of oil and NGL and 1,990 Mcf/d of gas (900 boe/d). Production is from the Second White Specks, Milk River, Bow Island, Mannville, Sawtooth and Livingstone formations. Oil production is treated at three Baytex-operated batteries and gas is processed at two outside-operated gas plants. During 2007, Baytex drilled one gas well and one oil well in this area. At year-end 2007, Baytex had 11,800 net undeveloped acres in this area.

United States

Baytex opened an office in Denver, Colorado during 2007 with the mandate of acquiring and developing oil and gas assets in the United Sates. Baytex's objectives in making U.S. investments are to increase geographical, product mix and currency diversification; to expose Baytex to a larger set of investment opportunities; to enhance long-term growth; and to better match Baytex's asset base to its investor base. At present, Baytex has conducted land acquisition activities in Wyoming and Utah, with first drilling expected in the second quarter of 2008. Baytex has no oil or gas production in the U.S. at present. At year-end 2007, Baytex had 10,200 net undeveloped acres in the United States.

MARKETING

Crude Oil

The year 2007 was marked by the unprecedented rise in world oil prices. OPEC cut oil output late in 2006 and again on February 1, 2007 to meet their pricing targets. Prices rose significantly on the back of supply uncertainty and moderate global demand growth. In January world crude oil prices were in the low US$50.00/bbl range and climbed steadily thereafter to nearly double in November. Overall we saw West Texas Intermediate ("WTI") – the proxy for world oil price – rise by 58% in 2007, the biggest annual rise so far this decade. World demand for oil and products

grew by about 1.1% in 2007 compared to 1.3% in 2006, reflecting slower growth in North American and European demand offset by continued strength in Asian demand. Supply concerns dominated the market as inventories fell to below the 5 year trend line.

The ongoing sub-prime mortgage and credit crisis in the U.S. created much uncertainty in the financial and commodity markets, adding to price volatility. For the most part, these financial considerations overshadowed geopolitical events in spite of the protracted conflicts in Iraq and Afghanistan and the fear of Iran's potential development of nuclear capabilities.

Benchmark WTI prices began the year around US$54.00 per barrel, climbed to an all-time high of US$99.29 in November, and ended the year at close to US$96.00. The average price for 2007 was US$72.31 per barrel compared to US$66.22 in 2006, an increase of 9%. The 5-year WTI average is US$53.51 per barrel.

Canadian crude oil prices, while enjoying the strength in world prices, were offset to a large degree by the strengthening of the Canadian dollar. Canadian Par crude at Edmonton averaged $76.38 per barrel in 2007 versus $72.80 per barrel in 2006, up only 5% for the year. The 5-year Canadian Par average price is $62.73 per barrel.

Canadian heavy sour crude price differentials widened out to nearly US$42.00 per barrel for Lloydminster Blend crude ("LLB") in December 2007 due to downstream refinery and pipeline operational outages, yet the average for the year was the same as 2006 at 33% of WTI. LLB to WTI differentials averaged US$23.83 per barrel in 2007 versus US$22.03 in 2006. The 5-year average Canadian heavy sour crude differential is US$17.89 per barrel (33% of WTI).

In spite of all of the volatility in underlying index, basis and quality price differentials, Baytex's conventional light crude oil and natural gas liquids prices averaged $65.53/bbl before hedging, $11.69/bbl higher than the $53.84 per barrel we received in 2006. This increase, while substantial, was also muted by the impact of the strong Canadian dollar.

In order to manage heavy oil pricing volatility, Baytex has entered into a series of physical sales agreements for delivery of heavy crude in 2008 and 2009. These contracts set the pricing at a fixed differential to WTI and require that Baytex deliver 15,340 barrels per day of LLB or Western Canadian Select ("WCS") heavy crude oil blend for 2008 and 10,340 barrels per day for 2009. Prices received from these contracts average 68% of WTI in 2008 and 67% in 2009.

WTI costless collars have been put in place for 2008 on 6,000 barrels per day at a weighted average price from US$63.33 per barrel to US$79.13 per barrel. No collars have yet been implemented for 2009.

The market and infrastructure solutions for Baytex's Seal area remain a work in progress. Management is confident that long term solutions will be developed to allow accelerated full-scale field development in 2010 and beyond.

Natural Gas

Natural gas prices in North America weakened in 2007, reflecting strong supply availability. Reduced drilling rig activity and falling production in Western Canada was more than offset by activity in the U.S. and a flood of liquified natural gas ("LNG") imports during the summer of 2007. High oil prices sustained gas values at levels that might have been much lower in a lower alternative energy price environment. U.S. inventories were at historically high levels throughout the year. In addition to the new supply from offshore LNG, there was little in the way of any weather related disruptions as suffered during the 2005 hurricane season. U.S. gas prices represented by the NYMEX futures contract, averaged US$6.86/MMBtu in 2007, a decrease of 6% from US$7.27 in 2006. Daily prices for Alberta gas delivered to the AECO "C" trading hub averaged $6.44/Mcf in 2007, down 1% from $6.51 in 2006. The five-year averages are US$6.85/MMBtu for the NYMEX contract, and $6.97/Mcf for Alberta daily prices.

Baytex received an average of $6.61 per mcf for 2007 natural gas sales compared to $7.13 in 2006, a 7% decrease.

For 2008, Baytex entered into several physical forward natural gas sales contracts with price collars. Contracted volumes total 7.1 MMcf/d during the period from the beginning of January to the end of October for 2008 with an average floor price of $6.65 per Mcf and an average ceiling price of $8.70 per Mcf. An additional series of contracts has been executed, totaling 9.5 MMcf/d for the 2008 calendar year with an average floor price of $6.49 per Mcf and an average ceiling price of $7.63 per Mcf. No price collar or other hedging has been undertaken for 2009.

OPERATIONS

Production

The Trust's average production for fiscal 2007 was 36,222 boe/d compared to 34,292 boe/d for fiscal 2006.

Light oil & NGL production increased by 47% to 5,483 bbl/d from 3,735 bbl/d for last year. Heavy oil production for 2007 increased by 4% to 22,092 bbl/d compared to 21,325 bbl/d in 2006. Natural gas production decreased by 6% to average 51.9 MMcf/d for 2007 compared to 55.4 MMcf/d for 2006. The increase in light oil and NGL volumes was primarily due to the acquisition of the Pembina assets. Heavy oil production increased slightly due to development activities and the acquisition of the Lindbergh assets. The decrease in natural gas production was largely due to natural declines during a year in which Baytex engaged in a very low level of gas development activity due to economic factors.

	Light Oil and NGL *(bbl/d)*	Heavy Oil *(bbl/d)*	Natural Gas *(MMcf/d)*	Oil Equivalent *(boe/d)*
2007				
Heavy Oil District	–	22,092	7.3	23,315
Conventional Oil and Gas District	5,483	–	44.6	12,907
Total Production	**5,483**	**22,092**	**51.9**	**36,222**
2006				
Heavy Oil District	–	21,325	8.8	22,791
Conventional Oil and Gas District	3,735	–	46.6	11,501
Total Production	3,735	21,325	55.4	34,292

Revenue

Petroleum and natural gas sales for 2007 increased by 11% to $618.9 million from $556.7 million for fiscal 2006. Benchmark WTI crude oil averaged US$72.31 per bbl for 2007, representing a 9% increase over the US$66.22 per bbl for 2006. However, the Trust's realized wellhead prices were reduced by a strengthening Canadian dollar, which averaged US$0.9304 in 2007 compared to US$0.8817 in 2006. The Trust's light oil and NGLs price averaged $65.53 per bbl for 2007, representing a 22% increase over the 2006 price of $53.84 per bbl. The heavy oil price increased 2% to $44.28 per bbl in 2007 from $43.57 per bbl in 2006. Natural gas prices were 7% lower in 2007, averaging $6.61 per Mcf compared to $7.13 per Mcf during the previous year. Overall, after accounting for $3.2 million of realized gain on financial derivative contracts, the Trust averaged $46.14 per boe for 2007, a 3% increase from $44.68 per boe received in the prior year.

For 2007, light oil and NGL revenue increased 79% from the same period last year due to a 22% increase in wellhead prices and a 47% in sales volume. Revenue from heavy oil increased 7% due to a 2% increase in wellhead prices and a 5% increase in sales volume. Revenue from natural gas decreased 13% compared to 2006, as production decreased 6% combined with a price decrease of 7%.

Gross Revenue Analysis

	2007		2006	
	$ thousands	$/Unit(1)	$ thousands	$/Unit(1)
Oil revenue (bbl)				
Light oil & NGL	**131,143**	**65.53**	73,387	53.84
Heavy oil	**362,549**	**44.28**	339,066	43.57
Derivative contract gain (loss)	**(3,164)**	**(0.39)**	2,529	0.32
Total oil revenue	**490,528**	**48.14**	414,982	45.38
Natural gas revenue (Mcf)	**125,235**	**6.61**	144,236	7.13
Total revenue (boe)	**615,763**	**46.14**	559,218	44.68

(1) Per-unit oil revenue is in $/bbl; per unit natural gas revenue is in $/Mcf.

Royalties

For the year ended December 31, 2007, royalties increased to $102.8 million from $85.0 million for last year. Total royalties in 2007 were 16.6% of sales, compared to 15.3% of sales for 2006. For 2007, royalties were 18.8% of sales for light oil, NGL and natural gas and 15.1% for heavy oil. Roylties are generally based on market index prices realized by the industry in the period, with increasing rates as price and volume escalate. Baytex's increased effective royalty rate for heavy oil in 2007 was reflective of the higher market price.

Operating Expenses

Operating expenses for the year 2007 increased to $134.7 million from $112.4 million in 2006. Operating expenses were $10.09 per boe for 2007 compared to $8.98 per boe for the prior year. In 2007, operating expenses were $9.61 per boe of light oil, NGL and natural gas and $10.40 per barrel of heavy oil compared to $8.58 and $9.23, respectively, for the year earlier.

Transportation Expenses

Transportation expenses for the year ended December 31, 2007 were $28.8 million compared to $24.3 million for 2006. These expenses were $2.16 per boe in 2007 compared to $1.95 in 2006. Transportation expenses were $0.80 per boe of light oil, NGL and natural gas and $3.01 per barrel of heavy oil in 2007, compared to $0.87 and $2.60, respectively, in 2006.

Net Revenue

	Light oil & NGL *($/bbl)*		Heavy Oil *($/bbl)*		Total Oil & NGL *($/bbl)*		Natural Gas *($/Mcf)*		BOE *($/boe)*	
	2007	2006	2007	2006	2007	2006	2007	2006	2007	2006
Sales price(1)	**65.53**	53.84	**44.28**	43.57	**48.45**	45.10	**6.61**	7.13	**46.38**	44.48
Royalties	**(12.99)**	(7.84)	**(6.68)**	(6.37)	**(7.91)**	(6.59)	**(1.17)**	(1.23)	**(7.70)**	(6.80)
Operating costs	**(10.79)**	(11.17)	**(10.40)**	(9.23)	**(10.48)**	(9.52)	**(1.48)**	(1.25)	**(10.09)**	(8.98)
Transportation	**(0.66)**	(1.16)	**(3.01)**	(2.60)	**(2.55)**	(2.38)	**(0.15)**	(0.13)	**(2.16)**	(1.95)
Net revenue	**41.09**	33.67	**24.19**	25.37	**27.51**	26.61	**3.81**	4.52	**26.43**	26.75

(1) Sales price is before realized loss/gain recognized on financial derivative contracts, and net of blending costs for heavy oil.

General and Administrative Expenses

General and administrative expenses for 2007 were $23.6 million, compared to $20.8 million for the prior year. On a per sales unit basis, these expenses were $1.77 per boe in 2007 and $1.67 per boe in 2006. The increase is attributable to escalating costs in the labour market and additional expenses associated with increasing regulatory compliance requirements which translated into higher legal, audit, and consulting fees. In accordance with our full cost accounting policy, no expenses were capitalized in either 2007 or 2006.

($ thousands)	**2007**	2006
Gross corporate expense	**32,132**	28,538
Operator's recoveries	**(8,567)**	(7,695)
Net expenses	**23,565**	20,843

Unit Based Compensation Expense

Compensation expense related to the Trust's unit rights incentive plan was $8.0 million for 2007 compared to $7.5 million for 2006.

Compensation expense associated with rights granted under the plan is recognized in income over the vesting period of the plan with a corresponding increase in contributed surplus. The exercise of trust unit rights are recorded as an increase in trust units with a corresponding reduction in contributed surplus.

Effective January 1, 2006, the Trust commenced using the binomial-lattice model to calculate the estimated fair value of the unit rights issued.

Interest Expense

In 2007, interest expense was $35.2 million compared to $35.0 million for last year. Interest expense was affected by the recognition of a $2.0 million gain on termination of the interest rate swap associated with the senior subordinated notes, a more favourable exchange rate on the U.S. dollar denominated interest expenses, offset by accretion of the discontinued fair value hedge and higher interest on increased bank borrowings.

Foreign Exchange

The foreign exchange gain for 2007 was $32.5 million compared to $0.1 million in the prior year. The 2007 gain is comprised of an unrealized foreign exchange gain of $32.6 million and a realized foreign exchange loss of $0.1 million. The 2006 gain was substantially unrealized. The 2007 unrealized gain is based on the translation of the U.S. dollar denominated long-term debt at 1.0120 at December 31, 2007 compared to 0.8581 at December 31, 2006. The 2006 unrealized gain is based on translation at 0.8581 at December 31, 2006 compared to 0.8577 at December 31, 2005.

Depletion, Depreciation and Accretion

Depletion, depreciation and accretion increased to $189.5 million for the year ended December 31, 2007 compared to $152.6 million for 2006. On a sales-unit basis, the provision for the current year was $14.20 per boe compared to $12.19 per boe for 2006. The higher rate is due to the higher per unit cost of the proved reserves acquired at the end of the second quarter of 2007, as well as the resulting accounting adjustments for future income taxes and asset retirement obligations.

Taxes

On June 22, 2007, the federal government's bill (the "government's bill") regarding the taxation of distributions from publicly traded income trusts beginning January 1, 2011 received Royal Assent. As a result, a future income tax

recovery of $0.5 million was recognized in the second quarter relating to unutilized tax pools in the Trust which will be deductible to the Trust after 2010. The majority of the Trust's temporary differences resides in a consolidated subsidiary which is not subject to the distribution tax, and is therefore not impacted by this legislative change.

The government's bill provides that the new regime for income trusts will not apply until January 1, 2011 so long as the Trust experiences only "normal growth" and no "undue expansion". As part of the government's bill, a "safe harbour" limit was established for existing income trusts by limiting future equity issues to 40% of that trust's October 31, 2006 market capitalization for the period November 1, 2006 to December 31, 2007, and an additional 20% of this market capitalization for each of 2008, 2009 and 2010. For Baytex, the limits are approximately $730 million for 2006 / 2007 and $365 million for each of the subsequent three years. Issuance of equity or convertible debt beyond these limits will result in the new regime applying to the Trust before 2011.

Current tax expenses were $6.7 million for 2007 compared to $8.4 million last year. Current tax expense is comprised of $7.2 million of Saskatchewan Capital Tax and Resource Surcharge and a recovery of $0.5 million relating to prior period recoveries. The 2006 current tax expense included $8.2 million of Saskatchewan Capital Tax and Resource Surcharge, a recovery of $0.4 million of Large Corporation Taxes and $0.6 million of prior period adjustments.

The fiscal 2007 provision for future income taxes was a recovery of $49.4 million compared to a recovery of $41.2 million for the prior year. As a result of the Pembina/Lindbergh acquisition, Baytex recognized a future income tax liability of $74.5 million arising from the difference between the $64.0 million in tax pools acquired and the value assigned to the assets.

Federal Tax Pools

($ thousands)	2007	2006
Cumulative Canadian Exploration Expense	**36,872**	9,803
Cumulative Canadian Development Expense	**183,910**	124,111
Cumulative Canadian Oil and Gas Property Expense	**187,899**	164,781
Undepreciated Capital Cost	**217,939**	199,504
Other	**19,827**	28,633
Total Canadian federal tax pools	**646,447**	526,832
U.S. Tax Pools	**2,132**	–

Cash Flow from Operations

Cash flow from operations in 2007 increased 4% to $286.0 million from $274.7 million for the previous year. The increase is primarily due to higher production volumes. On a barrel of oil equivalent basis, cash flow from operations was $21.63 for 2007 compared to $21.94 for 2006.

Netback and Cash Flow

	2007		2006	
	$/boe	% of Revenue	$/boe	% of Revenue
Production revenue	46.38	100	44.48	100
Derivative contract gain (loss)	(0.24)	(1)	0.20	–
Royalties	(7.70)	(17)	(6.80)	(15)
Operating expenses	(10.09)	(22)	(8.98)	(20)
Transportation	(2.16)	(5)	(1.95)	(4)
Operating netback	26.19	56	26.95	61
General and administrative expenses	(1.77)	(4)	(1.67)	(4)
Interest expense	(2.38)	(5)	(2.68)	(6)
Current income taxes	(0.50)	(1)	(0.67)	(2)
Cash flow	21.54	46	21.93	49

Net Income

Net income for 2007 was $132.9 million compared to $147.1 million for 2006. The variance was due to higher operating and transportations costs, higher depletion rates, and higher general and administrative costs. These negative factors were partially offset by higher sales volumes and prices and a higher foreign exchange gain.

Capital Expenditures

Capital expenditures during 2007 totaled $394.1 million, with $148.7 million spent on exploration and development activities, $243.3 million on corporate acquisitions and $2.2 million spent on acquisitions net of dispositions of assets. For the year ended December 31, 2007, the Trust participated in the drilling of 136 (127.9 net) wells, resulting in 103 (98.3 net) oil wells, 20 (16.8 net) gas wells, seven (6.8 net) stratigraphic test and service wells and six (6.0 net) dry holes compared to prior year activities of 128 (117.6 net) wells, including 98 (91.3 net) oil wells, 21 (18.1 net) gas wells, three (3.0 net) stratigraphic test wells and six (5.2 net) dry holes.

	Year Ended December 31	
($ thousands)	2007	2006
Land	7,253	11,118
Seismic	1,994	2,202
Drilling and completion	108,106	97,273
Equipment	26,624	19,240
Other	4,742	2,548
Total exploration and development	148,719	132,381
Corporate acquisition (net of working capital)	243,273	–
Property acquisitions	2,877	1,530
Property dispositions	(723)	(828)
Total capital expenditures	394,146	133,083

Liquidity and Capital Resources

At December 31, 2007, total net monetary debt was $444 million compared to $367 million at the end of 2006. The increase is mainly attributable to the bank loan incurred to partially finance the acquisition of the Pembina and Lindbergh properties at the end of the second quarter. Bank borrowings and working capital deficiency at the end of 2007 was $250.1 million compared to total credit facilities of $370 million.

Baytex has a credit agreement with a syndicate of chartered banks. The credit facilities consist of an operating loan and a 364-day revolving loan. Advances under the credit facilities or letters of credit can be drawn in either Canadian or U.S. funds and bear interest at the agent bank's prime lending rate, bankers' acceptance rates plus applicable margins or LIBOR rates plus applicable margins. The syndicated credit facilities were increased from $300 million to $370 million during June 2007. The facilities are subject to semi-annual review and are secured by a floating charge over all of Baytex's assets. At December 31, 2007 a total of $241.7 million had been drawn under the credit facilities.

Baytex has US$179.7 million of 9.625% senior subordinated notes due July 15, 2010. These notes are unsecured and are subordinate to Baytex's bank credit facilities. Baytex had entered into an interest rate swap contract converting the fixed rate to a floating rate reset quarterly at the three month LIBOR rate plus 5.2% until the maturity of these notes. On November 29, 2007 Baytex terminated the interest rate swap contract. A gain on termination of $2.0 million has been recorded as reduction of interest expense.

Pursuant to various agreements with Baytex's creditors, we are restricted from making distributions to Unitholders where the distribution would or could have a material adverse effect on the Trust or its subsidiaries' ability to fulfill its obligations under Baytex's credit facilities.

The Trust believes that cash flow generated from operations, together with the existing bank facilities, will be sufficient to finance current operations, distributions to the Unitholders and planned capital expenditures for the ensuing year. The timing of most of the capital expenditures is discretionary and there are no material long-term capital expenditure commitments.

Unitholders' Equity

The Trust is authorized to issue an unlimited number of units. On October 18, 2004, the Trust implemented a Distribution Reinvestment Plan ("DRIP"). Under the DRIP, Canadian unitholders are entitled to reinvest monthly cash distributions in additional trust units of the Trust. At the discretion of the Trust, these additional units may be issued at 95% of the "weighted average closing price" from treasury, or acquired on the market at prevailing market prices. For the purposes of the units issued from treasury, the "weighted average closing price" is calculated as the weighted average trading price of trust units for the period commencing on the second business day after the distribution record date and ending on the second business day immediately prior to the distribution payment date, such period not to exceed 20 trading days. The Trust can also acquire trust units to be issued under the DRIP at prevailing market prices.

Non-controlling Interest

Baytex is authorized to issue an unlimited number of exchangeable shares. Exchangeable shares can be exchanged (at the option of the holder) into trust units at any time up to September 2, 2013. Up to 1.9 million exchangeable shares may be redeemed annually by Baytex for either cash or the issue of trust units. At December 31, 2007, there were 1.6 million exchangeable shares outstanding. During 2007, 7,000 exchangeable shares were exchanged for trust units. The number of trust units issuable upon exchange is based upon the exchange ratio in effect at the exchange date. The exchange ratio is calculated monthly based on the cash distribution paid divided by the weighted average trust unit price of the five-day trading period ending on the record date. The exchange ratio at December 31, 2007 was 1.67915 trust units per exchangeable share (December 31, 2006 – 1.51072 trust units per exchangeable share). Cash distributions are not paid on the exchangeable shares. The exchangeable shares are not publicly traded, although they may be transferred by the holder without first being exchanged to trust units.

The exchangeable shares of Baytex are presented as a non-controlling interest on the consolidated balance sheet because they fail to meet the non-transferability criteria necessary for them to be classified as equity. Net income has been reduced by an amount equivalent to the non-controlling interest's proportionate share of the Trust's consolidated net income with a corresponding increase to the non-controlling interest on the balance sheet.

Cash Distributions

During 2007 total cash distributions of $2.16 per unit were declared. The monthly cash distribution in 2006 was increased to $0.18 from $0.15 per unit, an amount maintained since the inception of the Trust in September 2003. The 2008 monthly distribution continues at $0.18 per unit until April 2008 at which time the monthly distribution will be increased to $0.20 per unit.

Cash Flow from Operations, Payout Ratio and Distributions

Cash flow from operations and payout ratio are non-GAAP terms. Cash flow from operations represents cash flow from operating activities before changes in non-cash working capital and other operating items. The Trust's payout ratio is calculated as cash distributions declared divided by cash flow from operations. The Trust considers these to be key measures of performance as they demonstrate the Trust's ability to generate the cash flow necessary to fund future distributions and capital investments.

	2007	2006
Cash flow from operating activities	$ 286,450	$ 261,982
Change in non-cash working capital	(5,140)	9,058
Asset retirement expenditures	2,442	1,747
Decrease (increase) in deferred charges and other assets	2,278	1,875
Cash flow from operations	$ 286,030	$ 274,662
Cash Distributions declared	$ 145,927	$ 143,072
Payout ratio	51%	52%

The Trust does not deduct capital expenditures when calculating the payout ratio. Due to the depleting nature of oil and gas assets, certain levels of capital expenditures are required to minimize production declines. In the oil and gas industry, due to the nature of reserves reporting, natural production declines and the risks involved in capital investment, it is not possible to distinguish between capital spent on maintaining productive capacity and capital spent on growth opportunities. Should the costs to explore for, develop or acquire oil and natural gas assets increase significantly, it is possible that the Trust would be required to reduce or eliminate its distributions in order to fund capital expenditures. There can be no certainty that the Trust will be able to maintain current production levels in future periods.

Cash distributions of $145.9 million during 2007 were funded through cash flow from operations of $286.0 million.

The following tables compare cash distributions to cash flow from operating activities and net income:

	2007	2006
Cash flow from operating activities	$ 286,450	$ 261,982
Actual cash distributions payable	145,927	143,072
Excess of cash flow from operating activities over cash distributions paid	$ 140,523	$ 118,910
Net Income	$ 132,860	$ 147,069
Actual cash distributions payable	145,927	143,072
Excess (shortfall) of net income over cash distributions paid	$ (13,067)	$ 3,997

It is Baytex's long term operating objective to substantially fund cash distributions and capital expenditures required to maintain production and reserves through cash flow from operating activities. Future production levels are highly dependant upon our success in exploiting our asset base and acquiring additional assets. The success of these activities, along with commodity prices realized are the main factors influencing the sustainability of our cash distributions. During periods of temporary decline in commodity prices, or periods of higher capital spending for acquisitions, it is possible that internally generated cash flow will not be sufficient to fund both cash distributions and capital spending. In these instances, the cash shortfall will be funded through a combination of equity and debt financing. As at December 31, 2007, Baytex had approximately $120 million in available credit facilities to fund such

shortfall. As Baytex strives to maintain a consistent distribution level under the guidance of prudent financial parameters, there may be times when a portion of our cash distributions would represent a return of capital.

For the year ended December 31, 2007, the Trust's cash distribution exceeded net income by $13.1 million with net income reduced by $153.6 million of non-cash items. Non-cash charges such as depletion, depreciation and accretion are not fair indicators for the cost of maintaining our productive capacity as they are based on historical costs of assets and not the fair value of replacing those assets under current market conditions.

Off Balance Sheet Arrangements and Contractual Obligations

The Trust has assumed various contractual obligations and commitments, as detailed in the table below, in the normal course of operations and financing activities. These obligations and commitments have been considered when assessing the cash requirements in the above discussion of future liquidity.

Contractual Obligations at December 31, 2007

	Payments Due			
($thousands)	Total	Within 1 year	1-3 years	4-5 years
Long-term debt	177,805	–	177,561	244
Interest payable on long-term debt	43,435	17,116	26,319	–
Convertible debentures	16,150	–	16,150	–
Interest payable on convertible debentures	3,241	1,080	2,161	–
Operating leases	5,983	2,459	3,318	206
Transportation agreements	3,505	1,812	1,498	195
Processing obligations	18,859	4,725	9,423	4,711
Total contractual obligations	268,978	27,192	236,430	5,356

Future interest payments related to our bank loan have not been included since future debt levels and interest rates are not known at this time.

The Trust also has ongoing obligations related to the abandonment and reclamation of well sites and facilities which have reached the end of their economic lives. Programs to abandon and reclaim them are undertaken regularly in accordance with applicable legislative requirements.

Risk and Risk Management

The exploration for and the development, production and marketing of petroleum and natural gas involves a wide range of business and financial risks, some of which are beyond the Trust's control. Included in these risks are the uncertainty of finding new reserves, the fluctuations of commodity prices, the volatile nature of interest and foreign exchange rates, and the possibility of changes to royalty, tax and environmental regulations. The petroleum industry is highly competitive and the Trust competes with a number of other entities, many of which have greater financial and operating resources.

The business risks facing the Trust are mitigated in a number of ways. Geological, geophysical, engineering, environmental and financial analyses are performed on new exploration prospects, development projects and potential acquisitions to ensure a balance between risk and reward. The Trust's ability to increase its production, revenues and cash flow depends on its success in not only developing its existing properties but also in acquiring, exploring for and developing new reserves and production and managing those assets in an efficient manner.

Despite best practice analysis being conducted on all projects, there are numerous uncertainties inherent in estimating quantities of petroleum and natural gas reserves, including future oil and natural gas prices, engineering data, projected future rates of production and the timing of future expenditures. The process of estimating petroleum and natural gas reserves requires substantial judgment, resulting in imprecise determinations, particularly

for new discoveries. An independent engineering firm evaluates the Trust's properties annually to determine a fair estimate of reserves. The Reserves Committee, consisting of qualified members of Baytex's Board of Directors, assists the Board in their annual review of the reserve estimates.

The provision for depletion and depreciation in the financial statements and the ceiling test are based on proved reserves estimates. Any future significant revisions could result in a full cost accounting write-down or material changes to the annual rate of depletion and depreciation.

The financial risks that the Trust is exposed to as part of the normal course of its business are managed, in part, with various financial derivative instruments, in addition to fixed-price physical delivery contracts. The use of derivative instruments is governed under formal internal policies and subject to limits established by the Board of Directors. Derivative instruments are not used for speculative or trading purposes.

The Trust's financial results can be significantly affected by the prices received for petroleum and natural gas production as commodity prices fluctuate in response to changing market forces. This pricing volatility is expected to continue. As a result, the Trust has a risk management program that may be used to protect the prices of oil and natural gas on a portion of the total expected production. The objective is to decrease exposure to market volatility and ensure the Trust's ability to finance its distributions and capital program.

The Trust's financial results are also impacted by fluctuations in the exchange rate between the Canadian dollar and the U.S. dollar. Crude oil and, to a large extent, natural gas prices are based on reference prices denominated in U.S. dollars, while the majority of expenses are denominated in Canadian dollars. The exchange rate also impacts the valuation of the U.S. dollar denominated long-term notes. The related foreign exchange gains and losses are included in net income. There is no plan at this time to fix the exchange rate on any of the Trust's long-term borrowings.

The Trust is exposed to changes in interest rates as Baytex's banking facilities are based on our lenders' prime lending rate and short-term Bankers' Acceptance rates.

The Trust's current position with respect to its financial derivative contracts is detailed in note 17 of the consolidated financial statements.

A summary of certain risk factors relating to our business is included in our Annual Information Form under the Risk Factors section.

CRITICAL ACCOUNTING POLICIES

A summary of Baytex's significant accounting policies can be found in Notes 1 and 2 to the Consolidated Financial Statements. The preparation of the consolidated financial statements in accordance with generally accepted accounting principles requires management to make judgments and estimates that affect the financial results of the Trust. These critical estimates are discussed below.

Oil and Gas Accounting

The Trust follows the full-cost accounting guideline to account for its petroleum and natural gas operations. Under this method, all costs associated with the exploration for and development of petroleum and natural gas reserves are capitalized on a country-by-country cost centre basis. These capitalized costs, along with estimated future development costs, are depleted and depreciated on a unit-of-production basis using estimated proved petroleum and natural gas reserves. By their inclusion in the unit-of-production calculation, reserves estimates are a significant component of the calculation of depletion and depreciation and site restoration expense.

Independent engineers engaged by the Trust use all available geological, reservoir, and production performance data to prepare the reserves estimates. These estimates are reviewed and revised, either upward or downward, as new information becomes available. Revisions are necessary due to changes in assumptions based on reservoir performance, prices, economic conditions, government restrictions and other relevant factors. If reserves estimates are revised downward, net income could be affected by increased depletion and depreciation.

Impairment of Petroleum and Natural Gas Assets

Companies that use the full-cost method of accounting for oil and natural gas operations are required to perform a ceiling test that calculates a limit for the net carrying cost of petroleum and natural gas assets. The net amount at which petroleum and natural gas properties are carried is subject to a cost recovery test (the "ceiling test"). The ceiling test is a two-stage process which is to be performed at least annually. The first stage of the test is a recovery test which compares the undiscounted future cash flow from proved reserves at forecast prices plus the cost less impairment of unproved properties to the net book value of the petroleum and natural gas assets to determine if the assets are impaired. An impairment loss exists when the net book value of the petroleum and natural gas assets exceeds such undiscounted cash flow. The second stage determines the amount of the impairment loss to be recorded. The impairment is measured as the amount by which the net book value of the petroleum and natural gas assets exceeds the future discounted cash flow from proved plus probable reserves at forecast prices. If reserves estimates are revised downward, net income could be affected by any additional depletion and deprecation recorded under the ceiling test calculation and could result in a significant accounting loss for a particular period.

Goodwill

As the result of an acquisition in 2004, goodwill of $37.8 million was recorded based on the excess of total consideration paid less the value assigned to the identifiable assets and liabilities acquired. The goodwill balance is assessed for impairment annually at year-end or more frequently if events or changes in circumstances indicate that the asset may be impaired. Impairment is charged to income in the period in which it occurs. The Trust has determined that there was no goodwill impairment as of December 31, 2007.

Asset Retirement Obligations

The amounts recorded for asset retirement obligations were estimated based on the Trust's net ownership interest in all wells and facilities, estimated costs to abandon and reclaim the wells and the facilities and the estimated time period during which these costs will be incurred in the future. Any changes to these estimates could change the amount recorded for asset retirement obligations and may materially impact the consolidated financial statements of future periods.

Future Income Taxes

The Trust is a unit trust for income tax purposes, and is taxable on taxable income not allocated to the unitholders. From inception on September 2, 2003, the Trust has allocated all of its taxable income to the unitholders, and accordingly, no provision for income taxes is required at the Trust level.

Baytex is subject to corporate income taxes and follows the liability method of accounting for income taxes. Under this method, future income taxes are recorded for the effect of any difference between the accounting and income tax basis of an asset or liability, using substantially enacted income tax rates. Future tax balances are adjusted for any changes in the tax rate and the adjustment is recognized in income in the period that the rate change occurs.

Unit-based Compensation

The Trust Unit Rights Incentive Plan ("The Plan") is described in note 12 to the Consolidated Financial Statements. The exercise price of the rights granted under the Plan may be reduced in future periods in accordance with the terms of the Plan. The Trust uses the binomial-lattice model to calculate the estimated fair value of the outstanding rights.

Compensation expense associated with rights granted under the plan is recognized in income over the vesting period of the plan with a corresponding increase in contributed surplus. The exercise of trust unit rights are recorded as an increase in trust units with a corresponding reduction in contributed surplus.

CHANGES IN ACCOUNTING POLICIES

Effective January 1, 2007, the Trust adopted the Canadian Institute of Chartered Accountants ("CICA") section 3855 "Financial Instruments – Recognition and Measurement", section 3865 "Hedges", section 1530 "Comprehensive Income" and section 3861 "Financial Instruments – Disclosure and Presentation". These standards have been adopted retrospectively. See Note 3 to the Consolidated Financial Statements for further detail and the impact on the Trust's financial statements from application of these new standards.

Effective January 1, 2007 the Trust also adopted the recommendation of CICA revised section 1506 "Accounting Changes" and section 3251 "Equity". The revised section 1506 provides clarification on the criteria for changes in accounting policies as well as the accounting treatment and disclosure of changes in accounting policies, changes in estimates and corrections of errors. The revised section 3251 establishes standards for the presentation of equity and changes in equity during the reporting period.

NEW ACCOUNTING PRONOUNCEMENTS

On December 1, 2006, the CICA issued three new accounting standards: Handbook Section 1535, Capital Disclosures, Section 3862, Financial instruments – Disclosures, and Section 3863, Financial instruments – Presentation. These new standards will be effective on January 1, 2008.

Section 1535 specifies the disclosure of an entity's objectives, policies and processes for managing capital, quantitative data about what the entity regards as capital, whether the entity has complied with any capital requirements, and if it has not complied, the consequences of such non-compliance. This Section is expected to have minimal impact on the Trust's financial statements.

Sections 3862 and 3863 specify a revised and enhanced disclosure on financial instruments. Increased disclosure will be required on the nature and extent of risks arising from financial instruments and how the entity manages those risks. This Section is expected to have minimal impact on the Trust's financial statements.

In February 2008, the CICA issued Section 3064, Goodwill and Intangible Assets, which replaces Sections 3062, Goodwill and Other Intangible Assets and 3450, Research and Development Costs. This section establishes standards for the recognition, measurement, presentation and disclosure of goodwill and intangible assets by profit-oriented enterprises subsequent to their initial measurement. The new standard will be effective on January 1, 2009. The Trust does not expect the adoption of this new Section to have a material impact on its consolidated financial statements.

In January 2006, the CICA Accounting Standards Board ("AcSB") adopted a strategic plan for the direction of accounting standards in Canada. As part of that plan, accounting standards in Canada for public companies are expected to converge with International Financial Reporting Standards ("IFRSs"). In March 2007, the AcSB released an "Implementation Plan for Incorporating IFRSs into Canadian GAAP", which assumes a convergence date of January 1, 2011. Following a progress review on February 13, 2008, the AcSB has confirmed this changeover date. The Trust continues to monitor and assess the impact of convergence of Canadian GAAP and IFRS.

FOURTH QUARTER 2007

The following discussion reviews the Trust's results of operations for the fourth quarter of 2007.

Production

Light oil and NGL production for the fourth quarter of 2007 increased by 123% to 8,123 bbl/d from 3,643 bbl/d a year earlier primarily as a result of the acquisition of the Pembina assets near the end of the second quarter of 2007. Heavy oil production was little changed from year-ago levels, averaging 22,196 bbl/d for the fourth quarter of 2007 compared to 22,416 bbl/d a year ago. Natural gas production increased by 5% to 53.9 MMcf/d for the fourth quarter of 2007 compared to 51.4 MMcf/d for the same period last year. The increase was primarily the result of the Pembina acquisition offsetting natural declines during a quarter in which Baytex engaged in a very low level of gas development activity due to economic factors.

Revenue

Petroleum and natural gas sales decreased 47% to $197.4 million for the fourth quarter of 2007 from $134.5 million for the same period in 2006. Revenue from light oil and NGL for the fourth quarter of 2007 increased 243% from the same period a year ago due to a 123% increases in sales volume and a 54% increase in wellhead prices. Revenue from heavy oil increased 30% as the result of a 22% increase in wellhead prices in addition to a 7% increase in sales volume. Revenue from natural gas decreased 6% as the result of a 5% increase in volume offset by a 10% decrease in wellhead prices.

Royalties

Total royalties increased to $32.5 million for the fourth quarter of 2007 from $18.5 million in 2006. Total royalties for the fourth quarter of 2007 were 16.5% of sales compared to 13.8% of sales for the same period in 2006. For the fourth quarter of 2007, royalties were 19.9% of sales for light oil, NGL and natural gas, and 13.7% for heavy oil. These rates compared to 16.6% and 12.1%, respectively, for the same period last year. Royalties are generally based on market index prices realized by the industry in the period, with rates increasing as price and volume escalate.

Operating Expenses

Operating expenses for the fourth quarter of 2007 increased to $38.7 million from $29.8 million in the corresponding quarter last year. Operating expenses were $10.25 per boe for the fourth quarter of 2007 compared to $9.36 per boe for the fourth quarter of 2006. For the fourth quarter of 2007, operating expenses were $9.67 per boe of light oil, NGL and natural gas, and $10.66 per barrel of heavy oil. The operating expenses for the same period a year ago were $9.15 and $9.47, respectively. The increase in operating costs for conventional oil and gas was in part due to the addition of higher cost sour operations at Pembina. In general, the inflationary environment affecting operating costs has not entirely subsided as certain cost categories such as property taxes, labour costs and fuel costs continued to increase. This is particularly prevalent in heavy oil operating areas as industry activity levels remain strong due to robust economics associated with the current heavy oil pricing environment.

Transportation Expenses

Transportation expenses for the fourth quarter of 2007 were $7.5 million compared to $6.4 million for the fourth quarter of 2006. These expenses were $1.98 per boe for the fourth quarter of 2007 compared to $2.00 for the same period in 2006. Transportation expenses were $0.67 per boe of light oil, NGL and natural gas and $2.92 per barrel of heavy oil. The corresponding amounts for fourth quarter of 2006 were $0.82 and $2.64, respectively.

General and Administrative Expenses

General and administrative expenses for the fourth quarter of 2007 increased to $6.8 million from $5.9 million a year earlier. On a per sales unit basis, these expenses were $1.81 per boe for the fourth quarter of 2007 compared to $1.84 per boe for the same period in 2006. In accordance with our full cost accounting policy, no expenses were capitalized in either period.

Unit Based Compensation Expense

Compensation expense related to the Trust's unit rights incentive plan was $1.8 million for the fourth quarter of 2007 compared to $2.2 million for the fourth quarter of 2006.

Interest Expense

Interest expense for the fourth quarter of 2007 remained consistent at $8.7 million compared to the same quarter last year. Interest expense was affected by the recognition of a $2.0 million gain on the termination of the interest rate swap associated with the senior subordinated notes, a more favourable exchange rate on the U.S. dollar

denominated interest expenses, offset by accretion of the discontinued fair value hedge and higher interest on increased bank borrowings.

Foreign Exchange

Foreign exchange gain in the fourth quarter of 2007 was $1.3 million compared to a loss of $9.0 million in the fourth quarter of 2006. The 2007 amount is comprised of an unrealized foreign exchange gain of $1.5 million and a realized foreign exchange loss of $0.2 million. The loss in the 2006 period was entirely unrealized. The current quarter's unrealized gain is based on the translation of the U.S. dollar denominated long-term debt at 1.0120 at December 31, 2007 compared to 1.0037 at September 30, 2007. The prior period loss is based on translation at 0.8581 at December 31, 2006 compared to 0.8966 at September 30, 2006.

Depletion, Depreciation and Accretion

The provision for depletion, depreciation and accretion for the fourth quarter of 2007 increased to $54.1 million from $39.5 million for the same quarter in 2006. On a sales-unit basis, the provision for the current quarter was $14.33 per boe compared to $12.38 per boe for the same quarter in 2006. The higher rate is due to the higher per unit cost of the proved reserves acquired at the end of the second quarter of 2007, as well as the resulting accounting adjustments for future income taxes and asset retirement obligations.

Net Income

Net income for the fourth quarter of 2007 was $41.4 million compared to $20.0 million for the fourth quarter in 2006. The variance was the result of higher production, higher sales prices, foreign exchange gains and future income tax recovery, offset by higher operating costs.

Trust Unit Information

At February 29, 2008, the Trust had 85,485,500 units outstanding and Baytex had 1,563,440 exchangeable shares outstanding. The exchange ratio at February 29, 2008 was 1.71212 trust units per exchangeable share.

At February 29, 2008, the Trust had $16.2 million convertible unsecured subordinated debentures outstanding which are convertible at the option of the holder at any time into fully paid trust units at a conversion price of $14.75 per unit.

Selected Annual Information

($ thousands, except per unit amounts)	2007	2006	2005
Financial			
Revenue	**618,927**	556,689	546,940
Net income[(1)]	**132,860**	147,069	79,876
Per unit basic[(1)]	**1.66**	2.02	1.19
Per unit diluted[(1)]	**1.60**	1.91	1.15
Total assets	**1,407,150**	1,079,629	1,105,567
Total long-term financial liabilities	**190,004**	228,597	283,565
Cash distributions declared per unit	**2.16**	2.16	1.80

(1) Net income and net income per unit is after non-controlling interest related to exchangeable shares.

Overall production for 2007 was 36,222 boe per day which represented a 6% increase from 34,292 boe per day in 2006. Average wellhead prices received during 2007 were $46.38 per boe compared to $44.48 during 2006. Production in 2005 was 35,177 boe per day. Average wellhead prices received in 2005 were $42.60 per boe.

Quarterly Information

($ thousands, except per unit amounts)	2007 TOTAL 2007	Q4	Q3	Q2	Q1	2006 TOTAL 2006	Q4	Q3	Q2	Q1
Revenue	618,927	197,438	164,228	127,511	129,750	556,689	134,541	145,754	140,163	136,231
Cash distributions declared per unit	2.16	0.54	0.54	0.54	0.54	2.16	0.54	0.54	0.54	0.54

Reconciliation of Net Income to Cash Flow from Operations:

Financial

($ thousands, except per unit amounts)	2007 TOTAL 2007	Q4	Q3	Q2	Q1	2006 TOTAL 2006	Q4	Q3	Q2	Q1
Net income(1)	$ 132,860	$ 41,353	$ 36,674	$ 31,050	$ 23,783	$ 147,069	$ 19,988	$ 42,040	$ 56,162	$ 28,879
Items not affecting cash:										
Unit based compensation	7,986	1,810	2,370	1,946	1,860	7,460	2,168	1,740	1,821	1,731
Amortization of deferred charges	–	–	–	–	–	1,267	304	314	200	449
Unrealized foreign exchange loss (gain)	(32,574)	(1,526)	(12,263)	(16,495)	(2,290)	(108)	8,997	54	(9,375)	216
Depletion, depreciation and accretion	189,512	54,086	51,525	42,541	41,360	152,579	39,488	38,285	36,639	38,167
Accretion on debentures & notes	2,164	2,059	35	34	36	189	33	42	31	83
Unrealized loss (gain) on financial derivatives	31,320	27,264	(599)	4,005	650	2,790	408	(11,762)	7,527	6,617
Future income taxes (recovery)	(49,369)	(27,659)	(3,895)	(11,307)	(6,508)	(41,169)	(10,167)	332	(24,742)	(6,592)
Non-controlling interest	4,131	1,280	1,110	981	760	4,585	2,300	885	1,202	198
Cash flow from operations(2)	$ 286,030	$ 98,667	$ 74,957	$ 52,755	$ 59,651	$ 274,662	$ 63,519	$ 71,930	$ 69,465	$ 69,748
Change in non-cash working capital	5,140	3,145	(308)	956	1,347	(9,058)	(1,913)	7,608	(15,667)	914
Asset retirement expenditures	(2,442)	(1,131)	(351)	(257)	(703)	(1,747)	(233)	(361)	(746)	(407)
Decrease in deferred charges and other assets	(2,278)	(550)	(576)	(576)	(576)	(1,875)	(409)	(488)	(489)	(489)
Cash flow from operating activities	$ 286,450	$ 100,131	$ 73,722	$ 52,878	$ 59,719	$ 261,982	$ 60,964	$ 78,689	$ 52,563	$ 69,766
Net income per unit(1)										
Basic	1.66	0.49	0.44	0.41	0.32	2.02	0.27	0.57	0.77	0.41
Diluted	1.60	0.48	0.43	0.39	0.30	1.91	0.26	0.54	0.73	0.39
Cash flow from operations per unit(2)										
Basic	3.57	1.17	0.90	0.69	0.79	3.77	0.85	0.98	0.96	0.99
Diluted	3.54	1.10	0.84	0.65	0.74	3.45	0.79	0.90	0.88	0.90
Cash flow from operating activities per unit										
Basic	3.58	1.19	0.88	0.69	0.79	3.59	0.81	1.07	0.72	0.99
Diluted	3.33	1.11	0.83	0.64	0.74	3.26	0.78	0.98	0.66	0.90

(1) Net income and net income per unit is after non-controlling interest related to exchangeable shares.

(2) The Trust evaluates performance based on net income and cash flow from operations. Cash flow from operations and cash flow per unit are not measurements based on generally accepted accounting principles ("GAAP"), but are financial terms commonly used in the oil and gas industry. Cash flow represents cash generated from operating activities before changes in non-cash working capital, deferred charges and other assets and deferred credits. The Trust's determination of cash flow may not be comparable with the calculation of similar measures for other entities. The Trust considers it a key measure of performance as it demonstrates the ability of the Trust to generate the cash flow necessary to fund future distributions to unitholders and capital investments.

	2007					2006				
	TOTAL 2007	Q4	Q3	Q2	Q1	TOTAL 2006	Q4	Q3	Q2	Q1
Production										
Light oil and NGLs *(bbl/d)*	5,483	8,123	6,556	3,705	3,484	3,735	3,643	3,594	3,619	4,089
Heavy oil *(bbl/d)*	22,092	22,196	22,593	21,444	22,129	21,325	22,416	21,325	20,413	21,134
Total oil and NGL *(bbl/d)*	27,575	30,319	29,149	25,149	25,613	25,060	26,059	24,919	24,032	25,223
Natural gas *(MMcf/d)*	51.9	53.9	53.7	49.3	50.6	55.4	51.4	54.9	54.7	60.6
Oil equivalent *(boe/d)*	36,222	39,304	38,094	33,372	34,041	34,292	34,631	34,074	33,154	35,319

	2007					2006				
	TOTAL 2007	Q4	Q3	Q2	Q1	TOTAL 2006	Q4	Q3	Q2	Q1
Average Prices										
WTI oil *(US$/bbl)*	72.31	90.68	75.38	65.03	58.27	66.22	60.21	70.48	70.70	63.48
Edmonton par oil *($/bbl)*	76.35	86.41	80.24	72.15	67.09	72.77	64.49	79.17	78.61	68.99
BTE light oil *($/bbl)*	65.53	74.77	67.82	54.42	51.08	53.84	48.62	57.94	57.83	51.33
BTE heavy oil *($/bbl)*	44.28	50.13	45.89	40.14	40.17	43.57	41.15	48.28	47.10	37.87
BTE total oil *($/bbl)*	48.45	56.37	50.85	42.26	41.66	45.10	42.19	49.68	48.71	40.05
BTE natural gas *($Mcf)*	6.61	6.31	5.80	7.02	7.43	7.13	7.03	6.35	6.68	8.36
BTE oil equivalent *($/boe)*	46.38	52.32	47.06	42.22	42.38	44.48	42.19	46.57	46.35	42.94

2008 Guidance

Baytex has set a 2008 capital budget of $150 million designed to maintain our production levels at an annual average between 37,000 boe/d and 38,000 boe/d. Sixty percent of this budget has been allocated to our heavy oil operations, with the planned drilling of 94 gross wells, including 15 to 20 primary horizontal producers in our Seal area in the Peace River oil sands region. The remainder of this budget has been allocated to our conventional oil and gas operations, including the drilling of 30 gross wells. Our 2008 production mix is forecast to be approximately 60% heavy oil, 18% light oil and NGL and 22% natural gas. During the first half of 2008, we plan to commence our thermal cyclic steam pilot project at Seal, where success could provide a material positive impact on Baytex's future heavy oil production and reserves. We will have a full year's benefit from the Pembina and Lindbergh assets acquired mid-year 2007. We also plan to proactively establish our operations in the United States to add to our investment and growth opportunities and to enhance the geographic diversity of our asset portfolio.

Baytex has entered into the following contracts to provide downside protection to 2008 cash flow while allowing for participation in a high commodity price environment. Baytex will continue to monitor market developments and may enter into additional similar contracts if deemed desirable.

Financial Derivative Contracts

OIL

	Period	Volume	Price	Index
Price collar	Calendar 2008	2,000 bbl/d	US$ 60.00 – $ 80.25	WTI
Price collar	Calendar 2008	2,000 bbl/d	US$ 65.00 – $ 77.05	WTI
Price collar	Calendar 2008	2,000 bbl/d	US$ 65.00 – $ 80.10	WTI

Foreign Currency

	Period	Amount	Rate
Swap	January 1, 2008 to June 30, 2008	US$ 10,000,000 per month	CAD/US$ 0.9935

Physical Sale Contracts

HEAVY OIL

	Period	Volume	Price
Price Swap – WCS Blend	Calendar 2008	13,340 bbl/d	WTI × 67.1% (weighted average)
Price Swap – LLB Blend	Calendar 2008	2,000 bbl/d	WTI less US$ 24.55
Price Swap – WCS Blend	Calendar 2009	10,340 bbl/d	WTI × 67.0% (weighted average)

GAS

	Period	Volume	Price
Price collar	January 1 to March 31, 2008	2,500 GJ/d	$ 6.65 – $ 8.60
Price collar	January 1 to March 31, 2008	2,500 GJ/d	$ 6.65 – $ 9.00
Price collar	January 1 to March 31, 2008	2,500 GJ/d	$ 6.65 – $ 8.05
Price collar	April 1, 2008 to October 31, 2008	5,000 GJ/d	$ 6.15 – $ 7.50
Price collar	April 1, 2008 to October 31, 2008	2,500 GJ/d	$ 6.15 – $ 9.35
Price collar	Calendar 2008	5,000 GJ/d	$ 6.15 – $ 7.00
Price collar	Calendar 2008	5,000 GJ/d	$ 6.15 – $ 7.46

The Trust is exposed to credit-related losses in the event of non-performance by counter-parties to these contracts. See note 17 to the December 31, 2007 consolidated financial statements for description of accounting treatment of these derivative contracts.

Environmental Regulation and Risk

All phases of the oil and natural gas business present environmental risks and hazards and are subject to environmental regulation pursuant to a variety of federal, provincial and local laws and regulations. Compliance with such legislation can require significant expenditures and a breach may result in the imposition of fines and penalties, some of which may be material. Environmental legislation is evolving in a manner expected to result in stricter standards and enforcement, larger fines and liability and potentially increased capital expenditures and operating costs. In 2002, the Government of Canada ratified the Kyoto Protocol (the "Protocol"), which calls for Canada to reduce its greenhouse gas emissions to specified levels. There has been much public debate with respect to Canada's ability to meet these targets and the Government's strategy or alternative strategies with respect to climate change and the control of greenhouse gases. Implementation of strategies for reducing greenhouse gases whether to meet the limits required by the Protocol or as otherwise determined, could have a material impact on the nature of oil and natural gas operations, including those of Baytex.

On March 8, 2007, the Alberta Government introduced Bill 3, the *Climate Change and Emissions Management Amendment Act*, which intends to reduce greenhouse gas emission intensity from large industries. Bill 3 states that facilities emitting more than 100,000 tonnes of greenhouse gases a year must reduce their emissions intensity by 12% starting July 1, 2007; if such reduction is not initially possible the companies owning the large emitting facilities will be required to pay $15 per tonne for every tonne above the 12% target. These payments will be deposited into an Alberta-based technology fund that will be used to develop infrastructure to reduce emissions or to support research into innovative climate change solutions. As an alternate option, large emitters can invest in projects outside of their operations that reduce or offset emissions on their behalf, provided that these projects are based in

Alberta. Prior to investing, the offset reductions, offered by a prospective operation, must be verified by a third party to ensure that the emission reductions are real.

The Federal Government released on April 26, 2007, its Action Plan to Reduce Greenhouse Gases and Air Pollution (the "Action Plan"), also known as ecoACTION and which includes the Regulatory Framework for Air Emissions. This Action Plan covers not only large industry, but regulates the fuel efficiency of vehicles and the strengthening of energy standards for a number of energy-using products. Regarding large industry and industry related projects the Government's Action Plan intends to achieve the following: (i) an absolute reduction of 150 megatonnes in greenhouse gas emissions by 2020 by imposing mandatory targets; and (ii) air pollution from industry is to be cut in half by 2015 by setting certain targets. New facilities using cleaner fuels and technologies will have a grace period of three years. In order to facilitate the companies' compliance of the Action Plan's requirements, while at the same time allowing them to be cost-effective, innovative and adopt cleaner technologies, certain options are provided. These are: (i) in-house reductions; (ii) contributions to technology funds; (iii) trading of emissions with below-target emission companies; (iv) offsets; and (v) access to Kyoto's Clean Development Mechanism.

The Federal Government and the Province of Alberta released on January 31, 2008 the final report of the Canada-Alberta ecoENERGY Carbon Capture and Storage Task Force, which recommends among others: (i) incorporating carbon capture and storage into Canada's clean air regulations; (ii) allocating new funding into projects through competitive process; and targeting research to lower the cost of technology.

Given the evolving nature of the debate related to climate change and the control of greenhouse gases and resulting requirements, it is not possible to predict the impact of those requirements on Baytex and our operations and financial condition.

The New Royalty Framework

On September 18, 2007, the Royalty Review Panel appointed by the Alberta government released a report entitled "Our Fair Share", providing recommendations on changes to the province's royalty regime. On October 25, 2007, the Alberta government announced the "New Royalty Framework", accepting many of the recommendations by the Royalty Review Panel. Major changes introduced to Alberta's royalty regime effective January 2009 are as follows:

Conventional oil – overall royalty rates will increase from the current maximum of 30% and 35% for old and new tiers. The new rates will range up to 50%, and rate caps will be raised to $120 per barrel for West Texas Intermediate (WTI) crude.

Natural gas – the Government will eliminate "old" and "new" tiers. Royalty rates, currently 5% to 35% will increase to 5% to 50%, based on a sliding rate formula sensitive to price and production volume, with rate caps at Cdn$16.59/GJ.

Oil Sands – currently, the pre-payout royalty rate is 1%. Under the new system, this rate will increase for prices above $55 per barrel, to a maximum of 9% when oil is priced at $120 or higher. Under the current regime, once an oil sands project reaches payout, the 1% royalty converts to a 25% net profits interest. Under the new regime, the net profits interest will apply at the rate of 25% when oil is less than $55 per bbl of WTI, and increase for every dollar oil is priced above $55 per barrel to a maximum of 40% when oil is priced at $120 or higher.

We cannot provide any assurance that the NRF will be implemented in the form proposed. If changes are made to the NRF before it is implemented by the Alberta government, such changes could result in the implementation of a new royalty regime that impacts us in a materially different manner, and that is more adverse to us, than the NRF as currently proposed.

As previously reported, we had requested that our reserves evaluator, Sproule, estimate the impact to our reserves evaluation based upon the currently released information on the new royalty regime. As of December 31, 2007, the province had not introduced the enabling legislation nor had they provided enough clarity on a number of issues for Sproule to provide a precise calculation of reserves and net present value under the new regime. It is possible that the announced changes may be amended before coming into force. Under the forecast price assumptions, Sproule

has estimated that the change to the net present value, discounted at 10%, of future net revenue from our proved plus probable reserves would be a reduction, estimated to be in range of 1.8% to 2.1%.

Broad-based Federal Tax Reductions

On October 30, 2007 the Federal Government presented the fall economic statement that proposed significant reductions in corporate income tax rates from 22.1% to 15%. The reductions will be phased in between 2008 and 2012. In addition, the Government announced that it plans to collaborate with the provinces and territories to reach a 25% combined federal-provincial-territorial statutory corporate income tax rate. The reduction in the federal rate will also reduce the specified investment flow-through ("SIFT") tax rate to 28% as compared to the rate of 31.5% previously announced subject to comments below concerning the provincial SIFT tax proposal.

Federal Government's Trust Tax Legislation

In 2007, the Federal Government introduced and passed into law trust taxation that will result in a tax of 29.5% (previously 31.5% as discussed above) on all trust distributions commencing January 1, 2011 (28% commencing January 1, 2012). Cash flow earned by the trust and not distributed has always been and continues to form part of taxable income at the trust level, which may result in cash taxes being paid if there are not sufficient tax pool claims and deductions obtained upon incurring capital expenditures or acquiring assets.

On December 20, 2007, the Finance Minister announced technical amendments to provide some clarification to the trust tax legislation. As part of the announcement the Minister indicated that the federal government intends to provide legislation in 2008 to permit income trusts to convert to taxable Canadian corporations without any undue tax consequence to investors or the trusts.

Currently, the SIFT Rules provide that the SIFT Tax rate will be the federal general corporate income tax rate (which is anticipated to be 16.5% in 2011) plus the provincial SIFT tax factor (which is set at a fixed rate of 13%), for a combined SIFT tax rate of 29.5% in 2011. On February 26, 2008, the Minister of Finance announced (the "Provincial SIFT Tax Proposal") that instead of basing the provincial component of the SIFT tax on a flat rate of 13%, the provincial component will be based on the general provincial corporate income tax rate in each province in which the SIFT has a permanent establishment. For purposes of calculating this component of the tax, the general corporate taxable income allocation formula will be used. Specifically, the Trust's taxable distributions will be allocated to provinces by taking half of the aggregate of:

- that proportion of the Trust's taxable distributions for the year that the Trust's wages and salaries in the province are of its total wages and salaries in Canada; and
- that proportion of the Trust's taxable distributions for the year that the Trust's gross revenues in the province are of its total gross revenues in Canada.

Under the Provincial SIFT Tax Proposal, the Trust would likely be considered to have a permanent establishment in Alberta, where the provincial tax rate in 2011 is expected to be 10%. Taxable distributions that are not allocated to any province would instead be subject to a 10% rate constituting the provincial component. There can be no assurance, however, that the Provincial SIFT Tax Proposal will be enacted as proposed.

CONTROLS AND PROCEDURES

Disclosure Controls and Procedures

As of December 31, 2007, an internal evaluation was conducted of the effectiveness of the Trust's disclosure controls and procedures as defined in Rule 13a-15 under the U.S. Securities Exchange Act of 1934 (the "Exchange Act') and as defined in Canada by Multilateral Instrument 52-109, Certification of Disclosure in Issuers' Annual and Interim Filings. Based on that evaluation, the Chief Executive Officer and the Chief Financial Officer concluded that the disclosure controls and procedures are effective to ensure that the information required to be disclosed in the reports that the Trust files or submits under the Exchange Act or under Canadian securities legislation is recorded,

processed, summarized and reported, within the time periods specified in the rules and forms therein. Disclosure controls and procedures include, without limitation, controls and procedures designed to ensure that the information required to be disclosed by the Trust in the reports that it files or submits under the Exchange Act or under Canadian securities legislation is accumulated and communicated to the Trust's management, including the senior executive and financial officers, as appropriate to allow timely decisions regarding the required disclosure.

Internal Control over Financial Reporting

Internal control over financial reporting is a process designed to provide reasonable assurance that all assets are safeguarded, transactions are appropriately authorized and to facilitate the preparation of relevant, reliable and timely financial information. Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Management is responsible for establishing and maintaining adequate internal control over financial reporting for the Trust. Management has assessed the effectiveness of the Trust's internal control over financial reporting as defined in Rule 13a-15(f) under the U.S. Securities Exchange Act of 1934 and as defined in Canada by Multilateral Instrument 52-109, Certification of Disclosure in Issuers' Annual and Interim Filings. The assessment was based on the framework in Internal Control – Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. Management concluded that the Trust's internal control over financial reporting was effective as of December 31, 2007. The effectiveness of the Trust's internal control over financial reporting as of December 31, 2007 has been audited by Deloitte & Touche LLP, as reflected in their report for 2007. No changes were made to our internal control over financial reporting during the year ended December 31, 2007, that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

ADDITIONAL INFORMATION

Additional information relating to the Trust, including the Annual Information Form, may be found on SEDAR at www.sedar.com.

MANAGEMENT'S REPORT

Management, in accordance with Canadian generally accepted accounting principles, has prepared the accompanying consolidated financial statements of Baytex Energy Trust. Financial and operating information presented throughout this Annual Report is consistent with that shown in the consolidated financial statements.

Management is responsible for the integrity of the financial information. Internal control systems are designed and implemented to provide reasonable assurance that assets are safeguarded from loss or unauthorized use and to produce reliable accounting records for financial reporting purposes.

Deloitte & Touche LLP were appointed by the Trust's unitholders to express an audit opinion on the consolidated financial statements. Their examination included such tests and procedures, as they considered necessary, to provide a reasonable assurance that the consolidated financial statements are presented fairly in accordance with Canadian generally accepted accounting principles.

The Board of Directors is responsible for ensuring that management fulfills its responsibilities for financial reporting and internal control. The Board exercises this responsibility through the Audit Committee, with assistance from the Reserves Committee regarding the annual review of our petroleum and natural gas reserves. The Audit Committee meets regularly with management and the independent registered chartered accountants to ensure that management's responsibilities are properly discharged, to review the consolidated financial statements and recommend that the consolidated financial statements be presented to the Board of Directors for approval. The Audit Committee also considers the independence of the external auditors and reviews their fees. The external auditors have access to the Audit Committee without the presence of management.

Raymond T. Chan, CA
Chief Executive Officer
Baytex Energy Ltd.

W. Derek Aylesworth, CA
Chief Financial Officer
Baytex Energy Ltd.

March 17, 2008

AUDITORS' REPORT

To the Unitholders of Baytex Energy Trust

We have audited the consolidated balance sheets of Baytex Energy Trust (the "Trust") as at December 31, 2007 and 2006 and the consolidated statements of income and comprehensive income, the consolidated statements of deficit and the consolidated statements of cash flows for the years then ended. These financial statements are the responsibility of the management of the Trust. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Trust as at December 31, 2007 and 2006 and the results of its operations and its cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

On March 17, 2008, we reported separately to the Board of Directors of Baytex Energy Ltd. and the Unitholders of Baytex Energy Trust on our audit, conducted in accordance with Canadian generally accepted auditing standards and the standards of the Public Company Accounting Oversight Board (United States), of the consolidated financial statements for the same period, prepared in accordance with Canadian generally accepted accounting principles but which included Note 19, Differences Between Canadian and United States Generally Accepted Accounting Principles.

Deloitte & Touche LLP

Calgary, Alberta
March 17, 2008

Deloitte & Touche LLP
Chartered Accountants

CONSOLIDATED BALANCE SHEETS

As at December 31, *(thousands of Canadian dollars)*	2007	2006
ASSETS		
Current assets		
Accounts receivable	$ 105,176	$ 64,716
Crude oil inventory	5,997	9,609
Financial derivative contracts (note 17)	–	3,448
Future income tax asset (note 14)	11,525	–
	122,698	77,773
Deferred charges and other assets	–	4,475
Petroleum and natural gas properties (note 5)	1,246,697	959,626
Goodwill	37,755	37,755
	$ 1,407,150	$ 1,079,629
LIABILITIES		
Current liabilities		
Accounts payable and accrued liabilities	$ 104,318	$ 71,521
Distributions payable to unitholders	15,217	13,522
Bank loan (note 6)	241,748	127,495
Financial derivative contracts (note 17)	34,239	1,055
	395,522	213,593
Long-term debt (note 7)	173,854	209,691
Convertible debentures (note 8)	16,150	18,906
Asset retirement obligations (note 9)	45,113	39,855
Deferred obligations (note 18)	113	2,391
Future income taxes (note 14)	153,943	118,858
	784,695	603,294
Non-controlling interest (note 11)	21,235	17,187
UNITHOLDERS' EQUITY		
Unitholders' capital (note 10)	821,624	637,156
Conversion feature of debentures (note 8)	796	940
Contributed surplus (note 12)	18,527	13,357
Deficit	(239,727)	(192,305)
	601,220	459,148
	$ 1,407,150	$ 1,079,629

Commitments and contingencies (note 18)

See accompanying notes to the consolidated financial statements.

On behalf of the Board

Naveen Dargan
Director, Baytex Energy Ltd.

Dale O. Shwed
Director, Baytex Energy Ltd.

CONSOLIDATED STATEMENTS OF INCOME AND COMPREHENSIVE INCOME

Years Ended December 31,	2007	2006
(thousands of Canadian dollars, except per unit data)		
Revenue		
Petroleum and natural gas sales	$ 618,927	$ 556,689
Royalties	(102,805)	(85,043)
Loss on financial derivatives (note 17)	(34,484)	(261)
	481,638	471,385
Expenses		
Operating	134,696	112,406
Transportation	28,796	24,346
General and administrative	23,565	20,843
Unit based compensation (note 12)	7,986	7,460
Interest (note 7)	35,242	34,973
Foreign exchange gain (note 15)	(32,494)	(121)
Depletion, depreciation and accretion	189,512	152,579
	387,303	352,486
Income before taxes and non-controlling interest	94,335	118,899
Taxes (recovery) (note 14)		
Current	6,713	8,414
Future	(49,369)	(41,169)
	(42,656)	(32,755)
Income before non-controlling interest	136,991	151,654
Non-controlling interest (note 11)	(4,131)	(4,585)
Net income / Comprehensive income	$ 132,860	$ 147,069

CONSOLIDATED STATEMENTS OF DEFICIT

Years Ended December 31,	2007	2006
(thousands of Canadian dollars, except per unit data)		
Deficit, beginning of year, as previously reported	$ (192,305)	$ (181,118)
Cumulative effect of change in accounting policy (note 3)	(6,215)	–
Deficit, beginning of year, restated	(198,520)	(181,118)
Net income	132,860	147,069
Distributions to unitholders	(174,067)	(158,256)
Deficit, end of year	$ (239,727)	$ (192,305)
Net income per trust unit (note 13)		
Basic	$ 1.66	$ 2.02
Diluted	$ 1.60	$ 1.91

See accompanying notes to the consolidated financial statements

CONSOLIDATED STATEMENTS OF CASH FLOWS

Years Ended December 31, *(thousands of Canadian dollars)*	2007	2006
CASH PROVIDED BY (USED IN):		
Operating activities		
Net income	$ 132,860	$ 147,069
Items not affecting cash:		
Unit based compensation (note 12)	7,986	7,460
Amortization of deferred charges	–	1,267
Unrealized foreign exchange gain (note 15)	(32,574)	(108)
Depletion, depreciation, and accretion	189,512	152,579
Accretion on debentures and notes (notes 7 & 8)	2,164	189
Unrealized loss on financial derivatives (note 17)	31,320	2,790
Future income tax recovery	(49,369)	(41,169)
Non-controlling interest (note 11)	4,131	4,585
	286,030	274,662
Change in non-cash working capital (note 15)	5,140	(9,058)
Asset retirement expenditures	(2,442)	(1,747)
Decrease in deferred charges and other assets	(2,278)	(1,875)
	286,450	261,982
Financing activities		
Increase in bank loan	114,253	3,907
Issue of trust units, net of issuance costs (note 10)	147,221	8,509
Payments of distributions	(144,609)	(141,453)
	116,865	(129,037)
Investing activities		
Petroleum and natural gas property expenditures	(148,719)	(132,381)
Corporate acquisition (note 4)	(243,273)	–
Acquisition of working capital (note 4)	(13,229)	–
Acquisition of petroleum and natural gas properties	(2,877)	(1,530)
Proceeds on disposal of petroleum and natural gas properties	723	828
Change in non-cash working capital (note 15)	4,060	138
	(403,315)	(132,945)
Change in cash and cash equivalents during the year	–	–
Cash and cash equivalents, beginning of year	–	–
Cash and cash equivalents, end of year	$ –	$ –

See accompanying notes to the consolidated financial statements.

1. BASIS OF PRESENTATION

Baytex Energy Trust (the "Trust") was established on September 2, 2003 under a Plan of Arrangement involving the Trust and Baytex Energy Ltd. (the "Company"). The Trust is an open-ended investment trust created pursuant to a trust indenture. Subsequent to the Plan of Arrangement, the Company is a subsidiary of the Trust.

The consolidated financial statements include the accounts of the Trust and its subsidiaries and have been prepared by management in accordance with Canadian generally accepted accounting principles ("GAAP") as described in note 2.

2. SIGNIFICANT ACCOUNTING POLICIES

Consolidation

The consolidated financial statements include the accounts of the Trust and its wholly owned subsidiaries from their respective dates of acquisition of the subsidiary companies. Inter-company transactions and balances are eliminated upon consolidation. Investments in unincorporated joint ventures are accounted for using the proportionate consolidation method as described under the "Joint Interests" heading.

Measurement Uncertainty

The preparation of the consolidated financial statements requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the consolidated financial statements and revenue and expenses during the reporting period. Actual results can differ from those estimates.

In particular, amounts recorded for depreciation and depletion and amounts used for ceiling test calculations are based on estimates of petroleum and natural gas reserves and future costs required to develop those reserves. The Trust's reserves estimates are evaluated annually by an independent engineering firm. By their nature, these estimates of reserves and the related future cash flows are subject to measurement uncertainty, and the impact on the consolidated financial statements of future periods could be material.

The amounts recorded for asset retirement obligations were estimated based on the Trust's net ownership interest in all wells and facilities, estimated costs to abandon and reclaim the wells and the facilities and the estimated time period during which these costs will be incurred in the future. Any changes to these estimates could change the amount recorded for asset retirement obligations and may materially impact the consolidated financial statements of future periods.

Cash and Cash Equivalents

Cash and cash equivalents include monies on deposit and short-term investments which have an initial maturity date at acquisition of not more that 90 days.

Crude Oil Inventory

Crude oil inventory, consisting of production in transit in pipelines at the balance sheet date, is valued at the lower of cost, using the weighted average cost method, or net realizable value. Costs include direct and indirect expenditures incurred in bringing the crude to its existing condition and location.

Petroleum and Natural Gas Operations

The Trust follows the full cost method of accounting for its petroleum and natural gas operations whereby all costs relating to the exploration for and development of petroleum and natural gas reserves are capitalized on a country-by-country cost centre basis and charged against income, as set out below. Such costs include land

acquisition, drilling of productive and non-productive wells, geological and geophysical, production facilities, carrying costs directly related to unproved properties and corporate expenses directly related to acquisition, exploration and development activities and do not include any costs related to production or general overhead expenses. These costs along with estimated future capital costs that are based on current costs and that are incurred in developing proved reserves are depleted and depreciated on a unit of production basis using estimated proved petroleum and natural gas reserves, with both production and reserves stated before royalties. For purposes of this calculation, petroleum and natural gas reserves are converted to a common unit of measurement on the basis of their relative energy content where six thousand cubic feet of gas equates to one barrel of oil. Costs of acquiring and evaluating unproved properties are excluded from costs subject to depletion and depreciation until it is determined whether proved reserves are attributable to the properties or impairment occurs. Unproved properties are evaluated for impairment on an annual basis.

Gains or losses on the disposition of petroleum and natural gas properties are recognized only when crediting the proceeds to costs would result in a change of 20 percent or more in the depletion rate.

The net amount at which petroleum and natural gas properties are carried is subject to a cost recovery test (the "ceiling test"). The ceiling test is a two-stage process which is performed at least annually. The first stage of the test is a recovery test which compares the undiscounted future cash flow from proved reserves at forecast prices plus the cost less impairment of unproved properties to the net book value of the petroleum and natural gas assets to determine if the assets are impaired. An impairment loss exists when the net book value of the petroleum and natural gas assets exceeds such undiscounted cash flow. The second stage determines the amount of the impairment loss to be recorded. The impairment is measured as the amount by which the net book value of the petroleum and natural gas assets exceeds the future discounted cash flow from proved plus probable reserves at forecast prices. Any impairment is recorded as additional depletion and depreciation.

Goodwill

Goodwill is the residual amount that results when the purchase price of an acquired business exceeds the fair value of the net identifiable assets and liabilities of the acquired business. Goodwill is stated at cost less impairment and is not amortized. The goodwill balance is assessed for impairment annually at year-end or more frequently if events or changes in circumstances indicate that the asset may be impaired. The test for impairment is conducted by the comparison of the net book value to the fair value of the Trust. If the fair value of the Trust is less than the net book value, impairment is deemed to have occurred. The extent of the impairment is measured by allocating the fair value of the Trust to the identifiable assets and liabilities at their fair values. Any remainder of this allocation is the implied fair value of goodwill. Any excess of the net book value of goodwill over this implied value is the impairment amount. Impairment is charged to income in the period in which it occurs.

Convertible Unsecured Subordinated Debentures

The debentures have been classified as debt net of the fair value of the conversion feature which has been classified as unitholders' equity. The debt portion will accrete up to the principal balance at maturity. The accretion and the interest paid are expensed as interest expense in the consolidated statements of income and comprehensive income. If the debentures are converted to trust units, a portion of the value of the conversion feature under unitholders' equity will be reclassified to unitholders' capital along with the principal amounts converted.

Asset Retirement Obligations

The Trust recognizes a liability at the discounted value for the future abandonment and reclamation costs associated with the petroleum and natural gas properties. The present value of the liability is capitalized as part of the cost of the related asset and amortized to expense over its useful life. The liability accretes until the date of expected settlement of the retirement obligations. The related accretion expense is recognized in the statement of income and comprehensive income. The provision will be revised for the effect of any changes to timing related to cash flow or undiscounted abandonment costs. Actual expenditures incurred for the purpose of site reclamation are charged to the asset retirement obligations to the extent that the liability exists on the balance sheet.

Joint Interests

A portion of the Trust's exploration, development and production activities is conducted jointly with others. These consolidated financial statements reflect only the Trust's proportionate interest in such activities.

Foreign Currency Translation

The accounts of integrated foreign operations are translated using the temporal method, whereby monetary items are translated into the reporting currency at the exchange rate in effect at the balance sheet date. Non-monetary items are translated at historical rates while revenues and expenses are translated using average rates over the period. Depreciation and amortization of assets is translated at historical exchange rates at the same exchange rates as the assets to which they relate. Translation gains and losses relating to the integrated foreign operations are included in the determination of net income for the period.

Foreign currency denominated monetary items are translated into Canadian dollars at the exchange rate in effect at the balance sheet date. Exchange gains and losses on long-term monetary items that do not qualify for hedge accounting are recognized in income.

Revenue and expenses are translated at the monthly average rate of exchange. Translation gains and losses are included in net income.

Revenue Recognition

Revenue associated with sales of crude oil, natural gas and natural gas liquids is recognized when title passes to the purchaser, normally at the pipeline delivery point for natural gas and crude oil except for products sold pursuant to a long-term crude oil supply contract where title transfer is at the refinery gate.

Financial Instruments

The Trust adopted the CICA Handbook Section 3855 Financial Instruments – Recognition and Measurement on January 1, 2007 (see note 3). Financial instruments are measured at fair value on initial recognition of the instrument. Measurement in subsequent periods depends on whether the financial instrument has been classified as "held-for-trading", "available-for-sale", "held-to-maturity", "loans and receivables", or "other financial liabilities" as defined by the accounting standard.

Financial assets and financial liabilities "held-for-trading" are measured at fair value with changes in those fair values recognized in net earnings. Financial assets "available-for-sale" are measured at fair value, with changes in those fair values recognized in Other Comprehensive Income ("OCI"). Financial assets "held-to-maturity", "loans and receivables" and "other financial liabilities" are measured at amortized cost using the effective interest method of amortization.

Cash and cash equivalents are designated as "held-for-trading" and are measured at fair value. Accounts receivable are designated as "loans and receivables". Accounts payable and accrued liabilities, distributions payable to unitholders, bank loan, long-term debt, deferred obligations and convertible debentures are designated as "other financial liabilities". The Trust expenses all financial instrument transaction costs immediately.

Financial Derivative Contracts

The Trust formally documents its risk management objectives and strategies to manage exposures to fluctuations in commodity prices, interest rates and foreign currency exchange rates. The risk management policy permits the use of certain derivative financial instruments, including swaps and collars, to manage these fluctuations. All transactions of this nature entered into by the Trust are related to underlying financial instruments or future petroleum and natural gas production. The Trust does not use financial derivatives for trading or speculative purposes. These instruments are classified as "held-for-trading" unless designated for hedge accounting. For derivative instruments that do not qualify as hedges or are not designated as hedges, the Trust applies the fair value method of accounting by recording an asset or liability on the Consolidated Balance Sheet and recognizes changes in the fair value of the instrument in the Statement of Income for the current period. The fair values of these instruments are based on quoted market prices or, in their absence, third-party market indications and forecasts.

The Trust has in place policies and procedures with respect to the required documentation and approvals for the use of derivative financial instruments. This documentation specifically ties the derivative instruments to their use and in

the case of commodities, to the mitigation of market price risk associated with cash flows expected to be generated. When applicable, the Trust identifies relationships between financial instruments and anticipated transactions, as well as its risk management objective and the strategy for undertaking the economic hedge transaction. When specific financial instruments are executed, the Trust assesses, both at the time of purchase and on an ongoing basis, whether the financial instrument used in a particular transaction is effective in offsetting changes in fair values or cash flows of the transaction.

Future Income Taxes

The Trust follows the liability method of accounting for income taxes. Under this method, future income taxes are recorded for the effect of any difference between the accounting and income tax bases of an asset or liability, using substantively enacted income tax rates. Future tax balances are adjusted for any changes in the tax rate and the adjustment is recognized in income in the period that the rate change occurs.

Unit-based Compensation

The Trust Unit Rights Incentive Plan is described in note 12. The exercise price of the rights granted under the Plan may be reduced in future periods in accordance with the terms of the Plan. The Trust uses the binomial-lattice model to calculate the estimated fair value of the outstanding rights.

Compensation expense associated with rights granted under the plan is recognized in income over the vesting period of the plan with a corresponding increase in contributed surplus. The exercise of trust unit rights are recorded as an increase in trust units with a corresponding reduction in contributed surplus.

Non-controlling Interest

The exchangeable shares of the Company are presented as a non-controlling interest on the consolidated balance sheet because they fail to meet the non-transferability criteria necessary in order for them to be classified as equity. Net income has been reduced by an amount equivalent to the non-controlling interest's proportionate share of the Trust's consolidated net income with a corresponding increase to the non-controlling interest on the consolidated balance sheet. As the exchangeable shares are converted to trust units, the exchange is accounted for as a step-acquisition where unitholders' capital is increased by the fair value of the trust units issued. The difference between the fair value of the trust units issued and the book value of the exchangeable shares is recorded as an increase in petroleum and natural gas properties.

Per-unit Amounts

Basic net income per unit is computed by dividing net income by the weighted average number of trust units outstanding during the year. Diluted per unit amounts reflect the potential dilution that could occur if trust unit rights were exercised, exchangeable shares were exchanged and convertible debentures were converted. The treasury stock method is used to determine the dilutive effect of trust unit rights, whereby any proceeds from the exercise of trust unit rights or other dilutive instruments and the amount of compensation expense, if any, attributed to future services and not yet recognized are assumed to be used to purchase trust units at the average market price during the year.

3. CHANGES IN ACCOUNTING POLICIES

Financial Instruments and Hedging Activities

Effective January 1, 2007, the Trust adopted the provisions of the Canadian Institute of Chartered Accountants ("CICA") section 3855 "Financial Instruments – Recognition and Measurement", section 3865 "Hedges", section 1530 "Comprehensive Income", section 3861 "Financial Instruments – Disclosure and Presentation" and section 3251 "Equity". The Trust has adopted these standards retrospectively and the comparative consolidated financial statements have not been restated. Transitional amounts have been recorded in deficit.

Financial Instruments

A. Classification

All financial instruments must initially be recognized at fair value on the balance sheet. All financial instruments must be classified into one of the following categories: "held for trading financial assets and liabilities", "loans and

receivables", "held to maturity investments", "available for sale financial assets" and "other financial liabilities". Subsequent measurement of the financial instruments is based on their classification.

The Trust has made the following classifications:

- Cash and cash equivalents are classified as held for trading and are measured at fair value, which approximates carrying value due to the short-term nature of these instruments. A gain or loss arising from a change in the fair value is recognized in net income in the current period.
- Accounts receivable are classified as loans and receivables and are initially measured at fair value and subsequently measured at amortized cost using the effective interest rate method. A gain or loss arising from a change in the fair value or the derecognition or impairment of assets is recognized in net income in the period.
- Accounts payable and accrued liabilities, distributions payable to unitholders, bank loan, long term debt and deferred obligations have been classified as other financial liabilities and are initially recognized at fair value. Upon issuance, the Trust's convertible debentures are classified into equity and financial liability components on the balance sheet at their fair value. The financial liability is classified as other financial liabilities. The above instruments are subsequently measured at amortized cost using the effective interest method. A gain or loss is recognized in net income in the period when the financial liability is derecognized or impaired and through the amortization process.
- All derivative instruments have been classified as held for trading and are measured at fair value. A gain or loss arising from a change in the fair value is recognized in net income in the current period.
- The Trust has elected to account for its physical commodity contracts which are entered into and continue to be held for the purpose of receipt or delivery of non-financial items in accordance with its expected purchase, sale or usage requirements as executory contracts rather than as non-financial derivatives. Prior to the adoption of the new standards, physical receipt and delivery contracts did not fall within the scope of the definition of a financial instrument and were accounted for as executory contracts.

B. Transaction Costs

The Trust has elected to expense all financial instrument transaction costs immediately.

C. Effective Interest Method

The Trust uses the effective interest method of amortization for the discount on its convertible debentures and the deferred adjustment on the long-term notes.

D. Embedded Derivatives

Embedded derivatives are derivatives embedded in a host contract. They are recorded separately from the host contract if all of the following are met: (1) their economic characteristics and risks are not closely related to the host contract; (2) a separate instrument with similar terms as the embedded derivative would meet the definition of a derivative; and (3) the hybrid instrument is not measured at fair value. The Company has selected January 1, 2007 as its transition date for accounting for any potential embedded derivatives.

Hedge Accounting

On January 1, 2007, the Trust chose to discontinue hedge accounting on its interest rate swap. Effective January 1, 2007 a financial liability was recorded on the balance sheet. Changes in the fair value of the swap were recorded in net income.

Comprehensive Income

Comprehensive income consists of net earnings and other comprehensive income ("OCI"). OCI includes gains and losses on derivatives designated as cash flow hedges, gains and losses arising from changes in fair value of available for sale assets and unrealized gains and losses on translating financial statements of self sustaining foreign operations, all net of tax. Accumulated other comprehensive income is a new equity category comprised of cumulative OCI. The Trust has not engaged in any transactions giving rise to OCI as of December 31, 2007.

Transitional Adjustment

The impact of adopting these standards as at January 1, 2007 is as follows:

	As at December 31, 2006	Adjustment Upon Adoption of New Standards	As at January 1, 2007
Assets			
Deferred charges	$ 4,475	$ (4,475)	$ –
Liabilities			
Financial derivative contracts	1,055	5,976	**7,031**
Long term debt	209,691	(5,976)	**203,715**
Future income taxes	118,858	(1,265)	**117,593**
		(1,265)	
Unitholders' Equity			
Unitholders' capital	637,156	3,005	**640,161**
Deficit	(192,305)	(6,215)	**(198,520)**
		(3,210)	
		$ (4,475)	

Accounting Changes

Effective January 1, 2007, the Trust adopted the recommendation of CICA revised section 1506 "Accounting Changes". The new standard provides clarification on the criteria for changes in accounting policies as well as the accounting treatment and disclosure of changes in accounting policies, changes in estimates and corrections of errors.

Future Accounting Changes

On December 1, 2006, the CICA issued three new accounting standards:

Handbook Section 1535, Capital Disclosures, Section 3862, Financial instruments – Disclosures, and Section 3863, Financial instruments – Presentation. These new standards will be effective on January 1, 2008.

Section 1535 specifies the disclosure of an entity's objectives, policies and processes for managing capital, quantitative data about what the entity regards as capital, whether the entity has complied with any capital requirements, and if it has not complied, the consequences of such non-compliance. This Section is expected to have minimal impact on the Trust's financial statements.

Sections 3862 and 3863 specify a revised and enhanced disclosure on financial instruments. Increased disclosure will be required on the nature and extent of risks arising from financial instruments and how the entity manages those risks.

In February 2008, the CICA issued Section 3064, Goodwill and Intangible Assets, which replaces Sections 3062, Goodwill and Other Intangible Assets and 3450, Research and Development Costs. This section establishes standards for the recognition, measurement, presentation and disclosure of goodwill and intangible assets by profit-oriented enterprises subsequent to their initial measurement. The new standard will be effective on January 1, 2009. The Trust does not expect the adoption of this new Section to have a material impact on its consolidated financial statements.

In January 2006, the CICA Accounting Standards Board ("AcSB") adopted a strategic plan for the direction of accounting standards in Canada. As part of that plan, accounting standards in Canada for public companies are expected to converge with International Financial Reporting Standards ("IFRSs"). In March 2007, the AcSB released an *"Implementation Plan for Incorporating IFRSs into Canadian GAAP"*, which assumes a convergence date of January 1, 2011. Following a progress review on February 13, 2008, the AcSB has confirmed this changeover date. The Trust continues to monitor and assess the impact of convergence of Canadian GAAP and IFRS.

4. CORPORATE ACQUISITION

On June 26, 2007, Baytex acquired all the issued and outstanding shares of a private company which has interests in certain petroleum and natural gas properties and related assets located primarily in the Pembina and Lindbergh areas of Alberta. The results of operations from these properties have been included in the consolidated financial statements since the acquisition on June 26, 2007. Subsequent to the acquisition, the private company was amalgamated with the Company.

This transaction has been accounted for using the purchase method of accounting. The estimated fair value of the assets acquired and liabilities assumed at the date of acquisition is summarized below:

Consideration for the acquisition	
Cash paid for property, plant and equipment	$ 241,092
Costs associated with acquisition	2,181
Cash paid for working capital	13,229
Total purchase price	$ 256,502
Allocation of purchase price	
Working capital	$ 13,229
Property, plant and equipment	320,036
Future income taxes	(74,524)
Asset retirement obligations	(2,239)
Total net assets acquired	$ 256,502

Amendments may be made to the purchase equation as the cost estimates and balance are finalized.

5. PETROLEUM AND NATURAL GAS PROPERTIES

	As at December 31	
	2007	2006
Petroleum and natural gas properties	$ 3,074,014	$ 2,600,834
Accumulated depletion and depreciation	(1,827,317)	(1,641,208)
	$ 1,246,697	$ 959,626

In calculating the depletion and depreciation provision for 2007, $65.0 million (2006 – $34.3 million) of costs relating to undeveloped properties were excluded from costs subject to depletion and depreciation. No general and administrative expenses have been capitalized since the inception of operations as a trust.

The net book value of petroleum and natural gas properties are subject to a ceiling test, which was calculated at December 31, 2007 using the following benchmark reference prices for the years 2008 to 2012 adjusted for commodity differentials specific to the Trust (notes 17 & 18):

	2008	2009	2010	2011	2012
WTI crude oil (US$/bbl)	89.61	86.01	84.65	82.77	82.26
AECO natural gas ($/MMBtu)	6.51	7.22	7.69	7.70	7.61

The prices and costs subsequent to 2012 have been adjusted for estimated inflation at an estimated annual rate of 2.0 percent. Based on the ceiling test calculation, the Trust's estimated undiscounted future net cash flows associated with proved reserves plus the cost less impairment of unproved properties exceeded the net book value of the petroleum and natural gas properties.

6. BANK LOAN AND CREDIT FACILITIES

The Company has a credit agreement with a syndicate of chartered banks. The credit facilities consist of an operating loan and a 364-day revolving loan. Advances or letters of credit (note 18) under the credit facilities can be drawn in either Canadian or U.S. funds and bear interest at the agent bank's prime lending rate, bankers' acceptance rates plus applicable margins or LIBOR rates plus applicable margins. On June 26, 2007 the credit facility was amended, increasing the aggregate amount to $370 million from $300 million. The credit facilities are

subject to semi-annual review and are secured by a floating charge over all of the Company's assets. At December 31, 2007 a total of $241.7 million were drawn under the credit facilities (December 31, 2006 – $127.5 million).

7. LONG-TERM DEBT

	As at December 31	
	2007	2006
10.5% senior subordinated notes (US$247)	$ 244	$ 288
9.625% senior subordinated notes (US$179,699)	177,561	209,403
	177,805	209,691
Discontinued fair value hedge	(3,951)	–
	$ 173,854	$ 209,691

Senior Subordinated Notes

The Company has US$247,000 senior subordinated notes bearing interest at 10.5 percent payable semi-annually with principal repayable on February 15, 2011. These notes are unsecured and are subordinate to the Company's bank credit facilities.

US$179.7 million of 9.625 percent senior subordinated notes due July 15, 2010 are unsecured and are subordinate to the Company's bank credit facilities. After July 15 of each of the following years, these notes are redeemable at the Company's option in whole or in part with not less than 30 nor more than 60 days' notice at the following redemption prices (expressed as percentage of the principal amount of the notes): 2007 at 104.813 percent, 2008 at 102.406 percent, 2009 and thereafter at 100 percent. These notes are carried at amortized cost net of a discontinued fair value hedge of $6.0 million recorded on adoption of Section 3865 (note 3). The notes will accrete up to the principal balance at maturity using the effective interest method. $2.0 million of accretion expense has been recorded for 2007. The effective interest rate is 10.666 percent. The Company entered into an interest rate swap contract converting the fixed rate to a floating rate reset quarterly at the three-month LIBOR rate plus 5.2 percent until the maturity of these notes (note 17). On November 29, 2007 the Company terminated the interest rate swap contract. A gain on termination of $2.0 million has been recorded reducing interest expense.

Interest Expense

The Company incurred interest expense on its outstanding debt as follows:

	2007	2006
Bank loan and miscellaneous financing	$ 13,376	$ 9,276
Amortization of deferred charges	–	1,267
Convertible debentures	1,295	2,614
Long-term debt	20,571	21,816
Total interest	$ 35,242	$ 34,973

8. CONVERTIBLE UNSECURED SUBORDINATED DEBENTURES

On June 6, 2005 the Trust issued $100 million principal amount of 6.5 percent convertible unsecured subordinated debentures for net proceeds of $95.8 million. The debentures pay interest semi-annually and are convertible at the option of the holder at any time into fully paid trust units at a conversion price of $14.75 per trust unit. The debentures mature on December 31, 2010 at which time they are due and payable.

The debentures have been classified as debt net of the fair value of the conversion feature which has been classified as unitholders' equity. This resulted in $95.2 million being classified as debt and $4.8 million being classified as equity. The debt portion will accrete up to the principal balance at maturity using the effective interest rate of 7.57 percent. The accretion, and the interest paid are expensed as interest expense in the consolidated statements of income and comprehensive income. If the debentures are converted to trust units, a portion of the value of the

conversion feature under unitholders' equity will be reclassified to unitholders' capital along with the principal amounts converted.

	Number of Debentures	Convertible Debentures	Conversion Feature of Debentures
Balance, December 31, 2005	77,152	$ 73,766	$ 3,698
Conversion	(57,533)	(55,049)	(2,758)
Accretion	–	189	–
Balance, December 31, 2006	19,619	18,906	940
Conversion	(2,999)	(2,895)	(144)
Accretion	–	139	–
Balance, December 31, 2007	**16,620**	**$ 16,150**	**$ 796**

9. ASSET RETIREMENT OBLIGATIONS

	As at December 31,	
	2007	2006
Balance, beginning of year	**$ 39,855**	$ 33,010
Liabilities incurred	**2,180**	1,199
Liabilities settled	**(2,442)**	(1,747)
Acquisition of liabilities	**2,239**	–
Disposition of liabilities	**(585)**	(122)
Accretion	**3,404**	2,678
Change in estimate(1)	**462**	4,837
Balance, end of year	**$ 45,113**	$ 39,855

(1) The change in status of wells and change in the estimated costs of abandonment and reclamations are factors resulting in a change in estimate.

The Trust's asset retirement obligations are based on the Trust's net ownership in wells and facilities. Management estimates the costs to abandon and reclaim the wells and the facilities and the estimated time period during which these costs will be incurred in the future. These costs are expected to be incurred over the next 52 years. The undiscounted amount of estimated cash flow required to settle the retirement obligations at December 31, 2007 is $268 million. Estimated cash flow has been discounted at a credit-adjusted risk free rate of 8.0 percent and an estimated annual inflation rate of 2.0 percent.

10. UNITHOLDERS' CAPITAL

Trust Units

The Trust is authorized to issue an unlimited number of trust units.

Trust Units	Number of units	Amount
Balance, December 31, 2005	69,283	$ 555,020
Issued on conversion of debentures	3,901	54,798
Issued on conversion of exchangeable shares	34	720
Issued on exercise of trust unit rights	1,250	8,509
Transfer from contributed surplus on exercise of trust unit rights	–	4,435
Issued pursuant to distribution reinvestment program	654	13,674
Balance, December 31, 2006	75,122	637,156
Issued from treasury for cash	7,000	142,135
Issued on conversion of debentures	203	3,037
Issued on conversion of exchangeable shares	12	230
Issued on exercise of trust unit rights	739	5,482
Transfer from contributed surplus on exercise of trust unit rights	–	2,816
Issued pursuant to distribution reinvestment program	1,464	27,763
Cumulative effect of change in accounting policy (Note 3)	–	3,005
Balance, December 31, 2007	**84,540**	**$ 821,624**

On October 18, 2004, the Trust implemented a Distribution Reinvestment Plan ("DRIP"). Under the DRIP, Canadian unitholders are entitled to reinvest monthly cash distributions in additional trust units of the Trust. At the discretion of the Trust, these additional units will be issued from treasury at 95 percent of the "weighted average closing price", or acquired on the market at prevailing market rates. For the purposes of the units issued from treasury, the "weighted average closing price" is calculated as the weighted average trading price of trust units for the period commencing on the second business day after the distribution record date and ending on the second business day immediately prior to the distribution payment date, such period not to exceed 20 trading days.

Trust units are redeemable at the option of the holder. The redemption price is equal to the lesser of 90 percent of the "market price" of the trust units on the TSX for the ten trading days after the trust units have been surrendered for redemption and the closing market price on the date the trust units have been surrendered for redemption. Trust units can be redeemed for cash to a maximum of $250,000 per month. Redemptions in excess of the cash limit, if not waived by the Trust, shall be satisfied by distribution of subordinate, unsecured redemption notes bearing interest at 12 percent per annum, due and payable no later than September 1, 2033.

11. NON-CONTROLLING INTEREST

The Company is authorized to issue an unlimited number of exchangeable shares. The exchangeable shares can be converted (at the option of the holder) into trust units at any time up to September 2, 2013. Up to 1.9 million exchangeable shares may be redeemed annually by the Company for either cash or the issue of trust units. The number of trust units issued upon conversion is based upon the exchange ratio in effect at the conversion date. The exchange ratio is calculated monthly based on the cash distribution paid divided by the weighted average trust unit price for the five-day trading period ending on the record date. The exchange ratio at December 31, 2007 was 1.67915 trust units per exchangeable share (2006 – 1.51072 trust units per exchangeable share). Cash distributions are not paid on the exchangeable shares. The exchangeable shares are not publicly traded, although they may be transferred by the holder without first being converted to trust units.

The exchangeable shares of the Company are presented as a non-controlling interest on the consolidated balance sheet because they fail to meet the non-transferability criteria necessary in order for them to be classified as equity. Net income has been reduced by an amount equivalent to the non-controlling interest's proportionate share of the Trust's consolidated net income with a corresponding increase to the non-controlling interest on the balance sheet.

	Number of Exchangeable Shares	Amount
Balance, December 31, 2005	1,597	$ 12,810
Exchanged for trust units	(24)	(208)
Non-controlling interest in net income	–	4,585
Balance, December 31, 2006	1,573	17,187
Exchanged for trust units	(7)	(83)
Non-controlling interest in net income	–	4,131
Balance, December 31, 2007	1,566	$ 21,235

As the exchangeable shares are converted to trust units, the exchange is accounted for as a step-acquisition whereby unitholders' capital is increased by the fair value of the trust units issued. The difference between the fair value of the trust units issued and the book value of the exchangeable shares is recorded as an increase in petroleum and natural gas properties.

12. TRUST UNIT RIGHTS INCENTIVE PLAN

The Trust has a Trust Unit Rights Incentive Plan (the "Plan") whereby the maximum number of trust units issuable pursuant to the plan is a "rolling" maximum equal to 10 percent of the outstanding trust units plus the number of trust units which may be issued on the exchange of outstanding exchangeable shares. Any increase in the issued and outstanding units will result in an increase in the available number of trust units issuable under the plan, and any exercises of incentive rights will make new grants available under the plan, effectively resulting in a re-loading of the number of rights available to grant under the plan. Trust unit rights are granted at the volume weighted average trading price of the trust units for the five trading days prior to the date of grant, vest over three years and have a

term of five years. The Plan provides for the exercise price of the rights to be reduced in future periods by a portion of the future distributions, subject to certain performance criteria.

The Trust recorded compensation expense of $8.0 million for the year ended December 31, 2007 ($7.5 million in 2006) related to the rights granted under the plan.

Effective January 1, 2006, the Trust has commenced using the binomial-lattice model to calculate the estimated weighted average fair value of $3.87 per unit for rights issued during 2007 ($4.34 per unit in 2006). The following assumptions were used to arrive at the estimate of fair values:

	2007	2006
Expected annual right's exercise price reduction	**$ 2.16**	$ 2.16
Expected volatility	**28%**	23% – 28%
Risk-free interest rate	**3.77% – 4.50%**	3.54% – 4.45%
Expected life of right (years)	**Various(1)**	Various(1)

(1) The binomial-lattice model calculates the fair values based on an optimal strategy, resulting in various expected life of unit rights. The maximum term is limited to five years by the Trust Unit Rights Incentive Plan.

The number of unit rights outstanding and exercise prices are detailed below:

	Number of rights	Weighted average exercise price(1)
Balance, December 31, 2005	5,366	$ 10.88
Granted	2,443	$ 21.66
Exercised	(1,250)	$ 6.81
Cancelled	(246)	$ 11.54
Balance, December 31, 2006	6,313	$ 14.00
Granted	2,642	$ 19.85
Exercised	(739)	$ 7.42
Cancelled	(554)	$ 16.91
Balance, December 31, 2007	7,662	$ 14.67

(1) Exercise price reflects grant prices less reduction in exercise price as discussed above.

The following table summarizes information about the unit rights outstanding at December 31, 2007:

Range of Exercise Prices	Number Outstanding at December 31, 2007	Weighted Average Remaining Term	Weighted Average Exercise Price	Number Exercisable at December 31, 2007	Weighted Average Exercise Price
		(years)			
$1.09 to $4.50	**551**	0.7	$ 2.27	**551**	$ 2.27
$4.51 to $8.00	**771**	1.9	$ 6.19	**745**	$ 6.15
$8.01 to $11.50	**1,495**	2.8	$ 10.23	**923**	$ 10.31
$11.51 to $15.00	**450**	3.0	$ 12.86	**169**	$ 12.56
$15.01 to $18.50	**477**	4.1	$ 17.77	**78**	$ 17.73
$18.51 to $21.89	**3,918**	4.3	$ 19.61	**551**	$ 19.94
$1.09 to $21.89	**7,662**	3.4	$ 14.67	**3,017**	$ 9.89

The following table summarizes the changes in contributed surplus:

Balance, December 31, 2005	$ 10,332
Compensation expense	7,460
Transfer from contributed surplus on exercise of trust unit rights(1)	(4,435)
Balance, December 31, 2006	13,357
Compensation expense	7,986
Transfer from contributed surplus on exercise of trust unit rights(1)	(2,816)
Balance, December 31, 2007	$ 18,527

(1) Upon exercise of rights, contributed surplus is reduced with a corresponding increase in unitholders' capital.

13. NET INCOME PER UNIT

The Trust applies the treasury stock method to assess the dilutive effect of outstanding trust unit rights on net income per unit. The weighted average exchangeable shares outstanding during the year, converted at the year-end exchange ratio, and the trust units issuable on conversion of convertible debentures, have also been included in the calculation of the diluted weighted average number of trust units outstanding:

2007	Net income	Trust units	Net income per trust unit
Net income per basic unit	$ 132,860	80,029	$ 1.66
Dilutive effect of trust unit rights	–	2,110	
Conversion of convertible debentures	855	1,206	
Exchange of exchangeable shares	4,131	2,630	
Net income per diluted unit	$ 137,846	85,975	$ 1.60

2006	Net income	Trust units	Net income per trust unit
Net income per basic unit	$ 147,069	72,947	$ 2.02
Dilutive effect of trust unit rights	–	2,592	
Conversion of convertible debentures	1,647	2,515	
Exchange of exchangeable shares	4,585	2,384	
Net income per diluted unit	$ 153,301	80,438	$ 1.91

The dilutive effect of trust unit incentive rights for the year ended December 31, 2007 did not include 4.1 million trust unit rights (2006 – 2.1 million) because the respective proceeds of exercise plus the amount of compensation expense attributed to future services and not yet recognized exceeded the average market price of the trust units during the year.

14. INCOME TAXES (RECOVERY)

The provision for (recovery of) income taxes has been computed as follows:

	2007	2006
Income before income taxes and non-controlling interest	$ 94,335	$ 118,899
Expected income taxes at the statutory rate of 34.02% (2006 – 37.00%)	32,094	43,992
Increase (decrease) in taxes resulting from:		
Resource allowance	–	(11,236)
Alberta royalty tax credit	–	(110)
Net income of the Trust	(62,615)	(56,261)
Non-taxable portion of foreign exchange gain	(5,424)	(20)
Effect of change in tax rate	(15,806)	(26,218)
Effect of change in opening tax pool balances	(834)	3,451
Effect of change in valuation allowance	2,075	1,597
Unit based compensation	2,717	2,760
Other	(1,576)	876
Recovery of taxes	(49,369)	(41,169)
Current taxes	6,713	8,414
Total tax	$ (42,656)	$ (32,755)

On June 22, 2007, Bill C-52 budget Implementation Act which contains legislative provisions to tax publicly traded income trusts in Canada received Royal Assent in the Canadian House of Commons. The new tax is not expected to apply to the Trust until 2011. As a result of the legislation becoming enacted an additional future tax recovery of $0.5 million has been recorded.

The net future income tax liability is comprised of the following:

	As at December 31	
	2007	2006
Future income tax liabilities:		
Petroleum and natural gas properties	$ 155,921	$ 136,955
Other	18,271	10,019
Future income tax assets:		
Asset retirement obligations	(11,796)	(11,987)
Loss carry-forward[(1)]	(8,058)	(12,049)
Other	(11,920)	(4,080)
Net future income tax liability	142,418	118,858
Current portion of net future income tax asset	(11,525)	–
Long-term portion of net future income tax liability	$ 153,943	$ 118,858

(1) $41 million of the loss carry-forward will expire in 2014, $18 million in 2015 and $3 million in 2016.

15. SUPPLEMENTAL INFORMATION

Change in Non-Cash Working Capital Items

	2007	2006
Current assets	$ (23,619)	$ 9,525
Current liabilities	32,819	(18,445)
	$ 9,200	$ (8,920)
Changes in non-cash working capital related to:		
Operating activities	$ 5,140	$ (9,058)
Investing activities	4,060	138
	$ 9,200	$ (8,920)

Supplemental Cash Flow Information

During the year the Trust made the following cash outlays in respect of interest expense and current income taxes:

	2007	2006
Interest	$ 32,321	$ 32,373
Current income taxes	$ 9,436	$ 7,636

Foreign Exchange Gains

	2007	2006
Unrealized foreign exchange gain	$ 32,574	$ 108
Realized foreign exchange gain (loss)	(80)	13
Total foreign exchange gain	$ 32,494	$ 121

16. FINANCIAL INSTRUMENTS

The Trust's financial instruments recognized in the balance sheet consist of cash and cash equivalents, accounts receivable, current liabilities, financial derivatives and long-term borrowings. The fair values of financial instruments other than bank loan and long-term borrowings approximate their book amounts due to the short-term maturity of these instruments.

The estimated fair values of the financial instruments have been determined based on the Trust's assessment of available market information and appropriate valuation methodologies; however, these estimates may not necessarily be indicative of the amounts that could be realized or settled in a market transaction. The fair value of the bank debt approximates its book value as it is at a market rate of interest. At December 31, 2007, the trading value of the Company's senior subordinated term notes was 102 percent in relation to par (2006 – 106 percent). The market value of the Trust's convertible debentures at December 31, 2007 was 125 percent in relation to par (2006 – 146 percent).

(a) Credit Risk

Most of the Trust's accounts receivable relate to oil and natural gas sales and are exposed to typical industry credit risks. The Trust manages this credit risk by entering into sales contracts with only credit worthy entities and reviewing its exposure to individual entities on a regular basis. The book value of the accounts receivable reflects management's assessment of the associated credit risks.

(b) Interest Rate Risk

The Trust is exposed to movements in interest rates. Debt is comprised of both variable rate bank facilities and fixed rate senior notes. The Trust manages interest by utilizing appropriate interest rate swaps and fixed rate notes.

(c) Currency Risk

The Trust is exposed to fluctuations in foreign currency as a result of its U.S. dollar denominated notes and crude oil sales based on U.S. dollar indices. These two factors function somewhat as a natural hedge. From time to time, we may also enter into agreements to fix the exchange rate of Canadian to United States dollar in order to lessen the impact of currency rate fluctuations.

(d) Commodity Risk

Oil and gas prices are extremely volatile and are affected by numerous factors beyond our control. We manage the risk associated with changes in commodity prices by utilizing price swaps for oil and price collars for natural gas.

17. FINANCIAL DERIVATIVE CONTRACTS

The nature of the Trust's operations results in exposure to fluctuations in commodity prices, exchange rates and interest rates. The Trust monitors and, when appropriate, utilizes derivative contracts to manage its exposure to these risks. The Trust is exposed to credit-related losses in the event of non-performance by counter-parties to these contracts.

At December 31, 2007, the Trust had the following derivative contracts:

Oil

	Period	Volume	Price	Index
Price collar	Calendar 2008	2,000 bbl/d	US$ 60.00 – $ 80.25	WTI
Price collar	Calendar 2008	2,000 bbl/d	US$ 65.00 – $ 77.05	WTI
Price collar	Calendar 2008	2,000 bbl/d	US$ 65.00 – $ 80.10	WTI

Foreign Currency

	Period	Amount	Strike Price
Swap	January 1, 2008 to June 30, 2008	US$ 10,000,000 per month	CAD/US$ 0.9935

This contract is extendable on similar terms on June 30, 2008, at the option of the counterparty, for a further six months to the end of 2008.

The financial derivative contracts are marked to market at the end of each reporting period, with the following reflected in the income statement:

	2007	2006
Realized gain (loss) on financial derivatives	$ (3,164)	$ 2,529
Unrealized loss on financial derivatives	(31,320)	(2,790)
Loss on financial derivatives	$ (34,484)	$ (261)

18. COMMITMENTS AND CONTINGENCIES

In 2007, the Trust entered into long-term crude oil supply contracts with third parties that require the delivery of 15,340 barrels per day of crude oil in 2008 and 10,340 in 2009. The details of these contracts are:

Heavy Oil

	Period	Volume	Price
Price Swap – WCS Blend	Calendar 2008	13,340 bbl/d	WTI × 67.1% (weighted average)
Price Swap – LLB Blend	Calendar 2008	2,000 bbl/d	WTI less US$ 24.55
Price Swap – WCS Blend	Calendar 2009	10,340 bbl/d	WTI × 67.0% (weighted average)

At December 31, 2007, the Trust had the following natural gas physical sales contracts:

Gas

	Period	Volume	Price
Price collar	January 1 to March 31, 2008	2,500 GJ/d	$ 6.65 – $ 8.60
Price collar	January 1 to March 31, 2008	2,500 GJ/d	$ 6.65 – $ 9.00
Price collar	January 1 to March 31, 2008	2,500 GJ/d	$ 6.65 – $ 8.05
Price collar	Calendar 2008	5,000 GJ/d	$ 6.15 – $ 7.00
Price collar	Calendar 2008	5,000 GJ/d	$ 6.15 – $ 7.46

Subsequent to December 31, 2007, the Trust added the following natural gas physical sales contracts:

Gas

	Period	Volume	Price
Price collar	April 1, 2008 to October 31, 2008	5,000 GJ/d	$ 6.15 – $ 7.50
Price collar	April 1, 2008 to October 31, 2008	2,500 GJ/d	$ 6.15 – $ 9.35

At December 31, 2007, the Trust had operating lease and transportation obligations as summarized below:

Operating Leases and Transportation Agreements

	Payments Due					
	Total	1 year	2 years	3 years	4 years	5 years
Operating leases	$ 5,983	$ 2,459	$ 2,435	$ 883	$ 124	$ 82
Transportation agreements	22,364	6,537	5,708	5,213	4,825	81
Total	$ 28,347	$ 8,996	$ 8,143	$ 6,096	$ 4,949	$ 163

Other

At December 31, 2007, there are outstanding letters of credit aggregating $4.9 million (2006 – $7.3 million) issued as security for performance under certain contracts.

The Company has future contractual processing obligations with respect to assets acquired. The fair value ($7.8 million) of the original obligation is being drawn down over the life of the obligations which continue until October 2008. The fair value of the remaining obligation at December 31, 2007 was $2.4 million, all of which was included in current liabilities.

In connection with a purchase of properties, Baytex became liable for contingent consideration whereby an additional amount would be payable by Baytex if the price for crude oil exceeds a base price in each of the succeeding six years. An amount payable was not reasonably determinable at the time of the purchase, therefore such consideration should be recognized only when the contingency is resolved. As at December 31, 2007, an additional $0.7 million was paid for year two's obligations ($0.5 million was paid for year one) under the agreement and has been recorded as an adjustment to the original purchase price of the properties. It is currently not determinable if further payments will be required under this agreement, therefore no accrual has been made.

The Trust is engaged in litigation and claims arising in the normal course of operations, none of which could reasonably be expected to materially affect the Trust's financial position or reported results of operations.

19. DIFFERENCES BETWEEN CANADIAN AND UNITED STATES GENERALLY ACCEPTED ACCOUNTING PRINCIPLES

The Consolidated Financial Statements have been prepared in accordance with accounting principles generally accepted in Canada ("Canadian GAAP"). The significant differences between Canadian and United States GAAP, as applicable to these consolidated financial statements and notes, are described in the Trust's Form 40-F, which is filed with the United States Securities and Exchange Commission.

RESERVES INFORMATION

The following table summarizes certain information with regard to Baytex's oil and gas reserves as evaluated by Sproule Associates Limited as at December 31, 2007. Additional information required under NI 51-101 is included in the Annual Information Form for fiscal 2007.

Summary of Oil and Gas Reserves (Forecast Prices and Costs)

	Light and Medium Oil		Heavy Oil	
	Gross[(1)]	Net[(2)]	Gross[(1)]	Net[(2)]
	(Mbbl)	*(Mbbl)*	*(Mbbl)*	*(Mbbl)*
PROVED				
Developed Producing	5,917	4,905	23,069	19,827
Developed Non-Producing	546	449	23,831	19,936
Undeveloped	3,574	2,948	38,169	33,860
TOTAL PROVED	10,037	8,302	85,069	73,623
PROBABLE	5,295	4,263	37,392	32,160
TOTAL PROVED PLUS PROBABLE	15,332	12,564	122,461	105,783

(1) "Gross" reserves are the working interest share of remaining reserves, before deduction of any royalties and excluding any royalty interest.

(2) "Net" reserves means Baytex's gross reserves less all royalties payable to others.

(3) Oil equivalent amounts have been calculated using a conversion rate of six thousand cubic feet of natural gas to one barrel of oil. BOEs may be misleading, particularly if used in isolation. A BOE conversion ratio of 6 Mcf: 1 bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

Reconciliation of Working Interest Reserves[(1)]
By Principal Product Type (Forecast Prices and Costs)

	Light and Medium Oil			Heavy Oil		
	Proved[(2)]	Probable[(2)]	Proved + Probable[(2)]	Proved[(2)]	Probable[(2)]	Proved + Probable[(2)]
	(Mbbl)	*(Mbbl)*	*(Mbbl)*	*(Mbbl)*	*(Mbbl)*	*(Mbbl)*
December 31, 2006	5,186	2,044	7,230	75,808	32,929	108,737
Extensions	72	21	93	8,252	3,187	11,439
Discoveries	–	–	–	–	–	–
Improved Recovery	329	322	651	3,362	1,127	4,489
Technical Revisions	(344)	(2,463)	(2,807)	1,989	(1,014)	975
Acquisitions	6,081	5,292	11,373	2,997	770	3,767
Dispositions	–	–	–	–	–	–
Economic Factors	114	79	193	725	393	1,118
Production	(1,401)	–	(1,401)	(8,064)	–	(8,064)
December 31, 2007	10,037	5,295	15,332	85,069	37,392	122,461

(1) Company interest reserves include solution gas but do not include royalty interest.

(2) Reserves information as at December 31, 2006 and 2007 is prepared in accordance with NI 51-101.

(3) Oil equivalent amounts have been calculated using a conversion rate of six thousand cubic feet of natural gas to one barrel of oil. BOEs may be misleading, particularly if used in isolation. A BOE conversion ratio of 6 mcf: 1 bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

Natural Gas Liquids		Natural Gas		Oil Equivalent[3]	
Gross[1]	Net[2]	Gross[1]	Net[2]	Gross[1]	Net[2]
(Mbbl)	*(Mbbl)*	*(MMcf)*	*(MMcf)*	*(Mboe)*	*(Mboe)*
2,853	2,254	78,326	64,413	44,893	37,722
372	324	10,056	8,467	26,426	22,119
378	287	15,587	12,544	44,719	39,185
3,603	2,864	103,969	85,425	116,038	99,026
1,870	1,417	44,888	36,621	52,038	43,944
5,473	4,282	148,857	122,046	168,076	142,970

Natural Gas Liquids			Natural Gas including solution gas			Oil Equivalent[3]		
roved[2]	Probable[2]	Proved + Probable[2]	Proved[2]	Probable[2]	Proved + Probable[2]	Proved[2]	Probable[2]	Proved + Probable[2]
(Mbbl)	*(Mbbl)*	*(Mbbl)*	*(MMcf)*	*(MMcf)*	*(MMcf)*	*(Mboe)*	*(Mboe)*	*(Mboe)*
3,462	1,014	4,476	108,421	39,637	148,058	102,528	42,592	145,120
80	41	121	3,680	977	4,657	9,017	3,412	12,429
9	2	11	2,275	586	2,861	388	100	488
–	–	–	2,767	718	3,485	4,152	1,569	5,721
(198)	170	(28)	(7,147)	(5,831)	(12,978)	254	(4,277)	(4,023)
838	638	1,476	11,871	8,140	20,011	11,895	8,056	19,951
–	–	–	–	–	–	–	–	–
12	5	17	1,039	661	1,700	1,025	586	1,611
(600)	–	(600)	(18,937)	–	(18,937)	(13,221)	–	(13,221)
3,603	1,870	5,473	103,969	44,888	148,857	116,038	52,038	168,076

Reserve Life Index

	2008[1] Production Target	Reserve Life Index (years) Total Proved	Proved Plus Probable
Oil and NGL (bbl/d)	29,150	9.3	13.5
Natural Gas (MMcf/d)	50.0	5.7	8.2
Oil Equivalent (boe/d)	37,500	8.5	12.3

(1) Mid-point of production guidance range of 37,000 to 38,000 boe/d

Net Present Value of Reserves (Forecast Prices and Costs)

Reserves Category *($ million)*	Summary of Net Present Value of Future Net Revenue As at December 31, 2007 Forecast Prices and Costs Before Income Taxes Discounted at (%/year)[1] 0%	5%	10%
Proved			
Developed Producing	1,250	1,098	982
Developed Non-Producing	670	464	340
Undeveloped	965	680	495
Total Proved	2,885	2,242	1,817
Probable	1,484	963	677
Total Proved Plus Probable	4,369	3,205	2,494

(1) Net present value of future net revenue does not represent fair market value of the reserves.

Sproule December 31, 2007 Price Forecast

Year	WTI Cushing *US$/Bbl*	Edmonton Par Price *C$/Bbl*	Hardisty Heavy 12 API *C$/Bbl*	AECO C-Spot *C$/MMbtu*	Inflation Rate *%/Yr*	Exchange Rate *$US/$Cdn*
2008	89.61	88.17	54.67	6.51	2.0	1.00
2009	86.01	84.54	52.42	7.22	2.0	1.00
2010	84.65	83.16	51.56	7.69	2.0	1.00
2011	82.77	81.26	50.38	7.70	2.0	1.00
2012	82.26	80.73	50.05	7.61	2.0	1.00
2013	82.81	81.25	50.38	7.78	2.0	1.00
2014	84.46	82.88	51.39	7.96	2.0	1.00
2015	86.15	84.55	52.42	8.14	2.0	1.00
2016	87.87	86.25	53.47	8.32	2.0	1.00

Thereafter prices are escalated at various rates

Finding, Development and Acquisition Costs

	2007	2006	2005	3-Year total
Capital Expenditures ($ millions)	**394.1**	133.1	152.4	679.6
Heavy oil/light oil and natural gas spending	**27%/73%**	54%/46%	58%/42%	38%/62%

	Proved			Proved Plus Probable		
($/boe)	**2007**	2006	3-Year Weighted Average	**2007**	2006	3-Year Weighted Average
Excluding future development costs:						
Finding and development costs	**10.03**	9.61	9.53	**9.17**	8.16	8.19
Acquisition costs (net of dispositions)	**20.63**	5.38	10.00	**12.30**	1.33	7.32
Finding, development and acquisition costs	**14.75**	9.57	9.71	**10.90**	4.69	7.83
Including future development costs:						
Finding and development costs	**8.82**	20.49	14.12	**9.27**	12.38	12.15
Acquisition costs (net of dispostions)	**22.93**	6.46	12.11	**14.05**	3.13	8.87
Finding, development and acquisition costs	**15.10**	20.36	13.35	**11.91**	7.69	10.76

(1) The aggregate of the exploration and development costs incurred in the most recent financial year and the change during that year in estimated future development costs generally will not reflect total finding and development costs related to reserves additions for that year.

(2) Oil equivalent amounts have been calculated using a conversion rate of six thousand cubic feet of natural gas to one barrel of oil. BOEs may be misleading, particularly is used in isolation. A BOE conversion ratio of 6 Mcf: 1 bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

Net Asset Value

The following net asset value calculation utilizes what is generally referred to as the "produce-out" net present value of Baytex's oil and gas reserves as evaluated by independent evaluators. It does not take into account the possibility of Baytex being able to recognize additional reserves beyond those included in the 2007 year-end report.

($ millions, except unit and per unit data)	Before Tax	After Tax
Net present value of proved plus probable reserves(1)	**2,494.3**	2,214.8
Value of undeveloped land(2)	**117.9**	117.9
Net debt(3)	**(427.9)**	(427.9)
Asset retirement obligations	**(45.1)**	(45.1)
Net asset value	**2,139.1**	1,859.7
Total trust units outstanding(4) (millions)	**88.3**	88.3
Net asset value per trust unit ($)	**24.23**	21.06

(1) Net present value of future net revenue discounted at 10% as evaluated by Sproule Associates Limited as at December 31, 2007. Net present value of future net revenue does not represent fair market value of the reserves.

(2) As evaluated by Baytex as at December 31, 2007 on 638,975 net acres of undeveloped land.

(3) Long-term debt net of working capital as at December 31, 2007, excluding convertible debentures and notional liabilities associated with the mark-to-market value of derivative contracts.

(4) Includes 84,539,945 trust units, 1,565,615 exchangeable shares converted at an exchange ratio of 1.67915 and 1,126,780 trust units issuable on the conversion of the $16.6 million outstanding convertible debentures as at December 31, 2007.

ADVISORY AND ABBREVIATIONS

Advisory

Certain statements in this report are "forward-looking statements" within the meaning of the United States Private Securities Litigation Reform Act of 1995 or within the meaning of applicable Canadian securities legislation. Specifically, this report contains forward-looking statements relating to Management's approach to operations, expectations relating to the number of wells, amount and timing of capital projects, foreign exchange rates, interest rates, worldwide and industry production, prices of oil and gas, heavy oil differentials, company production, cash flow, debt levels and cash distribution practices. The reader is cautioned that assumptions used in the preparation of such information, although considered reasonable by Baytex at the time of preparation, may prove to be incorrect. Actual results achieved during the forecast period will vary from the information provided herein as a result of numerous known and unknown risks and uncertainties and other factors. Such factors include, but are not limited to: general economic, market and business conditions; industry capacity; volatility in market prices for oil and natural gas; liabilities inherent in oil and natural gas operations; uncertainties associated with estimating oil and natural gas reserves; competition for, among other things, capital, acquisitions of reserves, undeveloped lands and skilled personnel; incorrect assessments of the value of acquisitions; fluctuation in foreign exchange or interest rates; stock market volatility and market valuations; geological, technical, drilling and processing problems and other difficulties in producing petroleum reserves; changes in income tax laws, royalty rates and incentive programs relating to the oil and gas industry and income trusts; changes in environmental and other regulations; risks associated with oil and gas operations; and other factors, many of which are beyond the control of Baytex. These risk factors are discussed in Baytex's Annual Information Form, form 40-F and Management's Discussion and Analysis filed with Canadian security regulatory authorities and the U.S. Securities and Exchange Commission. There is no representation by Baytex that actual results achieved during the forecast period will be the same in whole or in part as those forecast and Baytex does not undertake any obligation to update publicly or to revise any of the included forward-looking statements, whether as a result of new information, future events or otherwise, except as may be expressly required by applicable securities law.

Abbreviations

API	American Petroleum Institute
bbl	barrel
bbl/d	barrel per day
Bcf	billion cubic feet
*boe**	barrels of oil equivalent
*boe/d**	barrels of oil equivalent per day
Capex	capital expenditures
FD&A	finding, development and acquisition costs
F&D	finding and development costs
GAAP	generally accepted accounting principles
G&A	general and administrative
GJ	gigajoule
LLB	Lloyd Light Blend
Mbbl	thousand barrels
*Mboe**	thousand barrels of oil equivalent
Mcf	thousand cubic feet
Mcf/d	thousand cubic feet per day
MMbbl	million barrels
*MMboe**	million barrels of oil equivalent
MMBtu	million British Thermal Units
MMcf	million cubic feet
MMcf/d	million cubic feet per day
NAV	net asset value
NGL	natural gas liquids
NYMEX	New York Mercantile Exchange
NYSE	New York Stock Exchange
RLI	reserve life index
TSX	Toronto Stock Exchange
WTI	West Texas Intermediate

** BOEs may be misleading, particularly if used in isolation. In accordance with NI 51-101, a BOE conversion ratio for natural gas of 6 Mcf : 1 bbl has been used, which is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.*

CORPORATE INFORMATION

BOARD OF DIRECTORS

Edward Chwyl (2)(3)(4)
Chairman of the Board
Independent Businessman

John A. Brussa (2)(3)(4)
Partner
Burnet, Duckworth & Palmer LLP

Raymond T. Chan
Chief Executive Officer
Baytex Energy Trust

Naveen Dargan (1)(2)(4)
Independent Businessman

R. E. T. (Rusty) Goepel (1)
Senior Vice President
Raymond James Ltd.

Dale O. Shwed (1)(3)
President and CEO
Crew Energy Inc.

(1) Member of the Audit Committee
(2) Member of the Compensation Committee
(3) Member of the Reserves Committee
(4) Member of the Governance Committee

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AUDITORS

Deloitte & Touche LLP

BANKERS

The Toronto-Dominion Bank
Bank of Nova Scotia
BNP Paribas (Canada)
Fortis Capital (Canada) Ltd.
National Bank of Canada
Royal Bank of Canada
Société Générale
Union Bank of California

LEGAL COUNSEL

Burnet, Duckworth & Palmer LLP

OFFICERS

Raymond T. Chan
Chief Executive Officer

Anthony W. Marino
President & Chief Operating Officer

W. Derek Aylesworth
Chief Financial Officer

Randal J. Best
Senior Vice President,
Corporate Development

Stephen Brownridge
Vice President, Heavy Oil

Brett J. McDonald
Vice President, Land

Timothy R. Morris
Vice President, US Business Development

R. Shaun Paterson
Vice President, Marketing

Mark F. Smith
Vice President, Conventional Oil & Gas

Shannon M. Gangl
Corporate Secretary
Partner, Burnet, Duckworth & Palmer LLP

RESERVES ENGINEERS

Sproule Associates Limited

TRANSFER AGENT

Valiant Trust Company

EXCHANGE LISTING

Toronto Stock Exchange
Symbol: BTE.UN

New York Stock Exchange
Symbol: BTE

ANNUAL MEETING

Tuesday, May 20, 2008
3:00 p.m. (MST)
The Petroleum Club
319 5th Avenue SW
Calgary, Alberta, Canada

BAYTEX ENERGY TRUST
Suite 2200, Bow Valley Square II
205 5th Ave SW
Calgary, AB T2P 2V7

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